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July 23, 2019

Via eFiling

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Tri-State Generation and Transmission Association, Inc.
Open Access Transmission Tariff
FERC Electric Tariff Volume No. 2
Docket No. ER19-___-000

Dear Ms. Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission" or "FERC"),[2] and Rule 205 of the Commission's Rules of Practice and Procedure,[3] Tri-State Generation and Transmission Association, Inc. ("Tri-State") hereby submits its initial rate filing of its FERC Electric Tariff Volume No. 2 consisting of its proposed Open Access Transmission Tariff ("Tariff" or "OATT"). The Tariff establishes the rates, terms and conditions for transmission service over Tri-State's transmission facilities. The Tariff is presented in an electronic format compliant with the Commission's Order No. 714.[4]

To date, application of Section 201(f) of the FPA has exempted Tri-State from the Commission's jurisdiction under Part II of the FPA.[5] Currently, Tri-State remains a "non-jurisdictional" utility because it is wholly-owned by entities that are themselves exempt under

1 16 U.S.C. § 824d.

2 18 C.F.R. § 35.12 (2019).

3 18 C.F.R. § 385.205.

4 *See Electronic Tariff Filings*, Order No. 714, III FERC Stats. & Regs., Regs. Preambles ¶ 31,276 (2008), *order establishing procedures*, 130 FERC ¶ 61,047, *order establishing baseline filing schedule*, 130 FERC ¶ 61,228 (2010), *final rule*, Order No. 714-A, 147 FERC ¶ 61,115 (2014).

5 16 U.S.C. § 824(f). FERC's jurisdiction under Part II of the FPA does not extend to "the United States, a State or any political subdivision of a State, an electric cooperative that receives financing under the Rural Electrification Act of 1936 (7 U.S.C. § 901, *et seq*.) or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto." *See Delta-Montrose Elec. Ass'n*, 151 FERC ¶ 61,238, at P 26 (2015) ("We find that Tri-State is not subject to Commission regulation under sections 205 and 206 of the FPA because the exemption contained in section 201(f) of the FPA is applicable to Tri-State.").

Section 201(f).[6] Tri-State will cease to be wholly-owned by such entities on or about 60 days from the date hereof, upon the admission of one or more new Members/owners ("New Member") that will not be an electric cooperative or a governmental entity and will not directly or indirectly be wholly-owned by an electric cooperative or a governmental entity. Upon the effective date that such New Member is admitted, Tri-State will become a public utility subject to the Commission's jurisdiction under Part II of the FPA. Section 205 of the FPA requires that, as a jurisdictional public utility, Tri-State have all rates, terms and conditions of FERC jurisdictional service on file with the Commission. The Tariff submitted with this filing embodies rates, terms and conditions that will qualify as FERC jurisdictional service once New Member joins Tri-State on or about 60 days from the date of filing hereof.[7] Accordingly, Tri-State respectfully requests that the Commission accept Tri-State's FERC Electric Tariff Volume No. 2 for filing to be effective 60 days from the date of this filing.

In support of its initial rate filing, Tri-State submits the following:

I. INTRODUCTION

Tri-State is a wholesale generation and transmission cooperative ("G&T") operating on a non-for-profit basis with its principal place of business in Westminster, Colorado. Incorporated in 1952, Tri-State is a cooperative corporation organized and existing pursuant to the Colorado Cooperative Act.[8] Tri-State was formed by its Member Systems ("Members")[9] for the purpose of

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6 Tri-State paid off all of its outstanding debt with the U.S. Department of Agriculture's Rural Utilities Service ("RUS") in 2014. However, Tri-State remains non-jurisdictional because each of the Member/owners of Tri-State is either a public power district or an electric cooperative that does not currently sell more than 4,000,000 MWh annually; certain electric cooperative Members of Tri-State also currently have outstanding RUS debt.

7 Tri-State is also filing on this day: (i) an initial filing of its Wholesale Electric Service Contracts (Rate Schedules FERC No. 1 through No. 43); (ii) a stated rate tariff for the full requirements service that Tri-State provides its Members (FERC Electric Tariff Volume No. 1); and (iii) an Application for Authority to Charge Market-based Rates and a market-based rate tariff (FERC Electric Tariff Volume No. 3). Tri-State's wholly-owned subsidiary, Thermo Cogeneration Partnership, L.P., is also concurrently filing in a separate docket its own Application for Authority to Charge Market-based Rates and a market-based rate tariff.

8 Colo. Rev. Stat. § 7-55-101 (2018) (Cooperatives - General); Articles of Incorporation (2019).

9 Tri-State's Members are: Big Horn Rural Electric Company, Carbon Power and Light, Inc., Central New Mexico Electric Cooperative, Inc., Chimney Rock Public Power District, Columbus Electric Cooperative, Inc., Continental Divide Electric Cooperative, Inc., Delta-Montrose Electric Association, Empire Electric Association, Inc., Garland Light and Power Company, Gunnison County Electric Association, Inc., High Plains Power, Inc., High West Energy, Inc., Highline Electric Association, Jemez Mountains Electric Cooperative, Inc., K.C. Electric Association, Inc., La Plata Electric Association, Inc., The Midwest Electric Cooperative Corporation, Mora-San Miguel Electric Cooperative, Inc., Morgan County Rural Electric Association, Mountain Parks Electric, Inc., Mountain View Electric Association, Inc., Niobrara Electric Association, Inc., Northern Rio Arriba Electric Cooperative, Inc., Northwest Rural Public Power District, Otero County Electric Cooperative, Inc., Panhandle Rural Electric Membership Association, Poudre Valley Rural Electric Association, Inc., Roosevelt Public Power District, San Isabel Electric Association, Inc., San Luis Valley Rural Electric Cooperative, Inc., San Miguel Power Association, Inc., Sangre de Cristo Electric Association, Inc., Sierra Electric Cooperative, Inc., Socorro Electric Cooperative, Inc., Southeast Colorado Power Association, Southwestern Electric Cooperative, Inc., Springer Electric Cooperative, Inc., United Power, Inc., Wheat Belt Public Power District, Wheatland Rural Electric

providing wholesale power and energy to its Members for resale to their retail consumers. Tri-State is controlled by a 43-seat Board of Directors, with each of Tri-State's 43 Members occupying one seat on the Board. As such, the Members have significant control over the activities of Tri-State, and the rates it charges to its Members.

Tri-State Power Sales to Its Members

Tri-State provides wholesale electricity to its 43 electric distribution cooperatives and public power districts in Colorado, Nebraska, New Mexico, and Wyoming at cost-based rates pursuant to long-term Wholesale Electric Service Contracts. Tri-State's Membership is composed of 37 electric distribution cooperatives, 18 of which are located in Colorado, 11 of which are located in New Mexico, and eight of which are located in Wyoming. The remaining six Tri-State Members are public power districts located in Nebraska.

Tri-State's Member sales are spread geographically as follows: 65% in Colorado, 5% in Nebraska, 17% in New Mexico, and 13% in Wyoming. Collectively, Tri-State's Members serve more than 1.3 million retail customers, representing a 2018 coincident peak demand of approximately 2,974 MW, in Colorado, Nebraska, New Mexico, and Wyoming. The load served by Tri-State's Members consists of approximately 83% residential customers, 13% commercial customers, and 4% agricultural and other accounts. In 2018, Tri-State sold approximately 16.4 million MWhs to its Members. The 2018 revenues from those sales were approximately $1.3 billion.

As a G&T, Tri-State is engaged in the wholesale sale of power and the provision of transmission service in interstate commerce. Tri-State sells power to its Members and engages in limited off-system sales at wholesale, but it makes no sales of energy or capacity at retail. Tri-State is in the business of generating and transmitting electrical power for resale primarily to its Members under full requirements contracts, and secondarily for and to other wholesale customers. As noted above, Tri-State is not currently subject to regulation of its wholesale power rates by the Commission under an exemption to the FPA for electric cooperatives wholly-owned directly or indirectly by entities that are themselves exempt by Section 201(f) of the FPA.

Tri-State's Member rates currently are determined by its 43-Member Board of Directors. Tri-State's Board currently reviews the rates for sales to Members once each calendar year, as a part of its annual budget process. Tri-State's current power rates to Members, including its wholesale power firm service rate (Rate Schedule A-40), were unanimously approved by Tri-State's Board of Directors and have been in effect since 2017.

Currently, the rates Tri-State charges its Members for wholesale generation and transmission services are generally not subject to state regulation. However, Tri-State has been, and is, subject to potential efforts by one or more states to regulate its wholesale rates and impose regulatory requirements impacting those rates.

Association, Inc., White River Electric Association, Inc., Wyrulec Company, Y-W Electric Association, Inc.

Under New Mexico law, Tri-State is required to file Member rates with the New Mexico Public Regulatory Commission ("NMPRC"). The NMPRC only has regulatory authority over such rates in New Mexico in the event three or more New Mexico Members file protests and a request for review found to be qualified by the NMPRC. Under Colorado law, the Colorado Public Utilities Commission ("COPUC") may assert regulation over Tri-State with respect to certain matters, including resource planning, the issuance of a certificate of need for new generation or transmission construction, or upon a complaint from one or more Members. Until recently, the COPUC has not asserted jurisdiction over other matters, including the rates Tri-State charges its Members in Colorado. In 2013, COPUC asserted jurisdiction over a complaint from three Members in Colorado regarding Tri-State's wholesale power rate.[10] In 2018, one of Tri-State's Colorado Members, Delta-Montrose Electric Association ("DMEA"), filed a complaint with the COPUC requesting that it assert jurisdiction over Tri-State with respect to a dispute over the amount of exit charges and costs to be paid by DMEA in the event of its withdrawal from Tri-State.[11] The parties recently reached a settlement agreement and filed a notice of dismissal of the complaint with the COPUC. Tri-State is not presently subject to rate regulation under Nebraska law, where all of its Members are public power districts, or in Wyoming by the Wyoming Public Utilities Commission, based upon a 1969 decision of the U.S. Court of Appeals for the Tenth Circuit.[12]

Tri-State's rates, and its cooperative model, are premised on the core concept that the Member electric cooperatives and public power districts to which it provides service share equitably the costs incurred by Tri-State in providing them with that service. If one or more of the four states in which Tri-State operates were to regulate Tri-State's rates or impose new or different regulatory requirements impacting Tri-State's service rates to certain of its Members, Tri-State's operations could be disrupted and the costs of providing service could be distributed inequitably among Tri-State's Members. This situation arose several years ago in New Mexico with the suspension by the NMPRC of the effectiveness of Tri-State's rate to its New Mexico Members,[13] ultimately resulting in Tri-State's other Members bearing the cost and, in effect,

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[10] *See* Interim Decision Granting and Denying in Part Respondent Tri-State Generation and Transmission Association, Inc.'s Motion Contesting Interim Decision No. R13-1119-I, *La Plata Elec. Ass'n, Inc. v. Tri-State Generation & Transmission Ass'n, Inc.*, Case No. 13F-0145E at P 49 (Colo. Pub. Utils. Comm'n Jan. 3, 2014) (affirming Administrative Law Judge's conclusion that the COPUC is not precluded from asserting complaint jurisdiction over Tri-State). In that case, La Plata Electric Association, Empire Electric Association, and White River Electric Association filed a complaint case with the COPUC alleging that Tri-State's rate was unjust, unreasonable, and discriminatory. While the COPUC had not previously asserted rate jurisdiction over Tri-State, here, the COPUC stated that it had complaint jurisdiction and set the matter for hearing. The case settled after the hearing on jurisdiction but before the hearing on the merits.

[11] *See* Formal Complaint, *Delta-Montrose Elec. Ass'n v. Tri-State Generation & Transmission Ass'n, Inc.*, Proceeding No. 18F-0866E (Colo. Pub. Utils. Comm'n filed Dec. 6, 2018).

[12] *Tri-State Generation & Transmission Ass'n v. Wyo. Pub. Serv. Comm'n*, 412 F.2d 115, 118 (10th Cir. 1969) (holding that Wyoming PUC regulation of Tri-State would constitute an impermissible burden on interstate commerce).

[13] *See* Order Appoint Hearing Examiner and Suspending Rate Schedules, *In the Matter of Tri-State Generation & Transmission Ass'n, Inc.'s Advice Notice No. 15*, at P 8 (N.M. Pub. Reg. Comm'n, Dec. 20, 2012); *see also* Order Suspending Advice Notice No. 19's Rate Schedules, *In the Matter of Tri-State Generation & Transmission Ass'n, Inc.'s Advice Notice No. 19*, at P 19 (N.M. Pub. Reg. Comm'n, Dec. 11, 2013).

cross-subsidizing certain Members. It has the potential for arising again in New Mexico and other states in which Tri-States operates currently or in the future. Under these circumstances, Tri-State's Board of Directors has voted overwhelmingly in favor of Tri-State becoming subject to rate regulation by a single regulatory body, the FERC. In this regard, Tri-State is following in the footsteps of virtually every other similarly-situated G&T that operates in multiple states and is at the risk of disparate state regulation.[14]

Tri-State's Power Supply Resources

Tri-State currently serves its Members through a portfolio of ownership interests in generation, tolling arrangements, power purchase agreements, and open market purchases, each of which is described in detail in Tri-State's Application for Authority to Charge Market-based Rates and a market-based rate tariff (FERC Electric Tariff Volume No. 3) filed concurrently with this Tariff filing in a separate docket.

Most of the output of the Tri-State-owned/operated power plants and the power purchased by Tri-State under long-term agreements has been and is sold at wholesale to Tri-State's Members to serve their respective retail customers. Tri-State is concurrently filing these full requirements Wholesale Electric Service Contracts in a separate docket as Rate Schedules FERC Nos. 1 through 43.

Tri-State Transmission Facilities

Tri-State has ownership or capacity interests in approximately 5,665 miles of high-voltage transmission lines and owns or has major equipment ownership in approximately 409 substations and switchyards over which Tri-State transmits electricity to its Members, which in turn provide electric distribution service to their approximately 1.3 million retail customers in Colorado, Nebraska, New Mexico and Wyoming. Tri-State's transmission facilities are located in these four states and are interconnected with those of other utilities, including Western Area Power Administration, Nebraska Public Power District, Black Hills Colorado Electric, Inc., PacifiCorp, Public Service Company of Colorado, Platte River Power Authority, Colorado Springs Utilities, Basin Electric Power Cooperative, Tucson Electric Power, Public Service Company of New Mexico, and Deseret Generation & Transmission Cooperative. The majority of Tri-State's transmission facilities operate as part of the Western Interconnection. A small portion of Tri-State's facilities support its load centers in the Eastern Interconnection and are under the functional control of the Southwest Power Pool. Tri-State is not a Balancing Authority Area operator. Tri-State does not sell or distribute power at retail. Tri-State has in place a reciprocity Open Access Transmission Tariff, initially approved by the Commission in 2001 in

[14] *See, e.g., Wabash Valley Power Ass'n, Inc.*, 107 FERC ¶ 61,327, at 62,506 (2004); *Wolverine Power Supply Coop, Inc.*, 81 FERC ¶ 61,369 (1997); *Old Dominion Elec. Coop.*, Letter Order, Docket No. ER92-432-000 (May 18, 1992). Additionally, as noted above, Tri-State is no longer an RUS borrower, and its exemption from regulation under the FPA as a "public utility" is premised on its direct and indirect ownership by exempt entities, including entities that make annual sales of less than 4,000,000 MWhs. Certain of Tri-State's larger Members are expected to exceed this limit in the next several years. This would result in Tri-State becoming FERC-jurisdictional, unless it is able to rely on another exemption from the FPA. Also, like other similarly-situated G&Ts, Tri-State wants the flexibility to add other types of non-exempt Members, including power marketers and other service providers.

Tri-State Generation and Transmission Association, Inc., 96 FERC ¶ 61,268 (2001), under which Tri-State provides network integration, point-to-point transmission, interconnection, and other transmission-related services on its transmission system to neighboring utilities and other wholesale transmission customers. Tri-State intends to own and operate these transmission facilities pursuant to the Tariff included as Attachment C hereto, upon the effectiveness of the instant filing.

II. COMMUNICATIONS AND SERVICE

Communications regarding this filing should be addressed to the following persons, who are also designated for service in this proceeding:

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III. REQUIRED INFORMATION

A. List of Documents Submitted

Attachment	Description
A	Names and addresses of entities receiving a mailed copy of this filing.
B	FERC Electric Tariff Volume No. 2 (submitted in rtf format in compliance with Order No. 714).
C	Table with section-by-section description of deviations from the pro forma OATT.
D	Prepared Direct Testimony and Exhibits of Alfred W. Busbee in support of formula transmission rates in non-RTO areas of the Tri-State service territory.
E	Prepared Direct Testimony and Exhibit of Ryan Hubbard in support of the Real Power Loss Factor.
F	Prepared Direct Testimony and Exhibits of Robert C. Smith in support of reactive power and voltage service charges.

B. Requested Effective Date

Tri-State respectfully requests that the Commission accept this initial filing of its Tariff, FERC Electric Tariff Volume No. 2, without suspension or condition to become effective 60 days after the date of this filing, which coincides with the date that Tri-State expects to become subject to the Commission's jurisdiction under the FPA. Consistent with Section 35.3 of the Commission's regulations, Tri-State is submitting its initial filing of its Tariff no less than 60 days and no more than 120 days before the proposed effective date.

C. Description of Tri-State's OATT and Variations from the Pro Forma OATT

Tri-State is proposing an OATT largely based on the pro forma OATT the Commission issued in conjunction with Order Nos. 888,[15] 890,[16] and 1000[17] and their progeny, with certain modifications of specific provisions to accommodate Tri-State's unique circumstances and needs. The Commission allows transmission providers to propose changes to the pro forma OATT if they can demonstrate that their proposals are "consistent with or superior to" the Commission's pro forma OATT.[18] As explained below, Tri-State's proposed deviations from the pro forma OATT meet this standard, and therefore, the Commission should find them just and reasonable.

To facilitate the Commission's review of Tri-State's proposed OATT, Tri-State provides a complete list of the proposed changes and the reasoning for the modifications to the pro forma OATT on a section-by-section basis in the table accompanying this Transmittal Letter. A discussion of the more substantive modifications to the OATT and the justifications that Tri-State's proposed modifications are consistent with or superior to the pro forma OATT, where applicable, are set out below.

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15 *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 1991-1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *reh'g denied*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

16 *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,241, *order on reh'g and clarification*, Order No. 890-A, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

17 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000*, III FERC Stats. & Regs., Regs. Preambles ¶ 31,323 (2011), *order on reh'g and clarification*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *petition for review denied, S. Carolina Pub. Serv. Authority v. FERC*, No. 12-1232 (D.C. Cir. Aug. 15, 2014).

18 *See, e.g.*, Order 890 at P 135. *See also Sagebrush*, 130 FERC ¶ 61,093, at P 26, *order on reh'g*, 132 FERC ¶ 61,234 (2010); *Montana Alberta Tie, Ltd.*, 116 FERC ¶ 61,071, at PP 55-60 (2006).

1. Attachment K - Transmission Planning Process

Tri-State proposes a Transmission Planning Process in Attachment K that satisfies the Local, Regional and Interregional transmission planning and coordination requirements of the pro forma OATT and complies with the requirements of Order Nos. 890 and 1000.

Specifically, Tri-State's Attachment K provides for a coordinated, open, transparent, and participatory Local Planning Process that will facilitate local transmission planning to ensure the development of transmission infrastructure that maintains safe and reliable electric service and meets customers' needs on a non-discriminatory basis, while providing reliable, low cost electric power to its member cooperatives. In particular, Tri-State's proposed Local Planning Process will annually develop a transmission plan that identifies transmission facilities needed to maintain the reliability of Tri-State's facilities, maintain interconnection and transmission services across its facilities, and reliably serve the connected load. In doing so, Tri-State's Local Planning Process will provide for the consideration of Transmission Customer submitted data and transmission needs driven by local reliability, economics, and public policy requirements. When developing its transmission plan, Tri-State will hold at least one annual open planning meeting to permit all interested parties, including point-to-point and network transmission service customers, interconnecting neighboring transmission providers, regulatory agencies, and all other stakeholders, to provide input into and comments on the plan. Tri-State will make its criteria, assumptions, and data used in developing the underlying transmission plans as well as all meeting notices and documents available on its website. The transmission plan will be developed on a comparable and non-discriminatory basis to meet anticipated transmission needs, avoid unnecessary duplication of facilities, and avoid imposing unreasonable costs on Tri-State's member cooperatives and its customers.

Tri-State's proposed Attachment K also provides for both Regional and Interregional Transmission Planning that satisfy the specific requirements of the pro forma OATT. Tri-State is a Member of the WestConnect Planning Region by virtue of executing the WestConnect Planning Participation Agreement.[19] Consequently, Tri-State's proposed Attachment K incorporates the common tariff language for implementing Order Nos. 890 and 1000 Regional Transmission Planning Process for the WestConnect Planning Region and Interregional Transmission Planning Process for the Western Interconnection.[20] The Commission has found that substantially similar Regional and Interregional Planning provisions in Tri-State's proposed

[19] WestConnect Planning Participation Agreement Amended and Restated February 8, 2016, located at www.westconnect.com and on file with the Commission. Currently, Tri-State participates in the WestConnect Regional Planning Process as a Coordinating Transmission Owner and may elect whether to accept Cost Allocation pursuant to Order No. 1000. After becoming FERC-jurisdictional, Tri-State will be an Enrolled Transmission Owner and will be subject to Order No. 1000 Cost Allocation for transmission projects for which it is identified as a beneficiary. *See* Tri-State, OATT, Attachment K, Sections III.A.2.c and VI.

[20] *See Pub. Serv. Co. of Col.*, 142 FERC ¶ 61,206 (2013), *order on reh'g and compliance*, 148 FERC ¶ 61,213 (2014), *order on reh'g and compliance*, 151 FERC ¶ 61,128 (2015), *aff'd in part and vacated in part*, *El Paso Elec. Co. v. FERC*, 832 F.3d 495 (5th Cir. 2016), *order on remand*, 161 FERC ¶ 61,188 (2017), *reh'g denied*, 163 FERC ¶ 61,204 (2018) (approving WestConnect's Regional Transmission Planning Process); *Pub. Serv. Co. of New Mexico*, 149 FERC ¶ 61,247 (2014), *order on compliance and clarification*, 151 FERC ¶ 61,189 (2015) (approving WestConnect's Interregional Planning Process).

Attachment K are consistent with, or superior to, the pro forma OATT and complies with the requirements of Order Nos. 890 and 1000 for other Members of WestConnect Planning Region.[21] Therefore, the Commission should accept Tri-State's proposed Attachment K in the instant filing.

2. Real Power Losses

Tri-State proposes a Real Power Loss Factor for point-to-point and network transmission service taken on Tri-State's transmission system. Accordingly, Tri-State replaces the brackets in sections 15.7 and 28.5 of the pro forma OATT with Tri-State's proposed Real Power Loss Factor. In support of the Real Power Loss Factor, Tri-State provides the testimony of Ryan J. Hubbard, (Exhibit No. TS-006).

As discussed in Mr. Hubbard's testimony, the calculation of the expected transmission line losses was based on four types of losses: current losses, transformer excitation, substation station service, and corona losses. Mr. Hubbard then calculated values for each type of line loss over several operating conditions. These values were totaled and then divided by a calculation of Tri-State's load to establish a percent system loss. This percent system loss was weighted based on assumed operational hours throughout the year to determine the total weighted real power loss factor of 3.378% to be used in Tri-State's OATT.

3. Ancillary Services - Schedules 3, 4, 5, and 6

Schedules 3, 4, 5, and 6 of the pro forma OATT require the Transmission Customer to purchase from Transmission Provider or make alternative comparable arrangements for the following ancillary services: (i) regulation and frequency response service; (ii) energy imbalance service; (iii) operating reserve - spinning reserve service; and (iv) operating reserve - supplemental reserve service, respectively. Further, Schedules 3, 5, and 6, include specific language that "[t]he amount of and charges for [the ancillary service] are set forth below."

As discussed in Mr. Rob Smith's testimony (Exhibit No. TS-008), Tri-State is not a Balancing Authority Area ("BAA") (*i.e.*, Control Area) operator. Consequently, Tri-State does not perform these services, but it can help arrange for the BAA operator to perform these ancillary services for the Transmission Customer, consistent with Section 3 of the OATT, and pass-through the costs charged to Tri-State by that BAA operator. Therefore, out of an abundance of caution, Tri-State makes clear that, despite statements in the schedules to the contrary, not including charges for these services in the schedules is not an oversight or a

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[21] *See Xcel Energy Services, Inc.*, Letter Order, Docket No. ER16-2503 (Oct. 27, 2016) (approving Attachment R (Transmission Planning Process) to Public Service Company of Colorado's OATT). The provisions for the Regional and Interregional Transmission Planning Processes in Tri-State's proposed Attachment K are the same as in PSCo's Attachment R, with two limited exceptions. First, for the Coordination at the Western Interconnection Level (Section IV), Tri-State removes the references to the Western Electricity Coordination Council Transmission Expansion Planning Policy Committee ("TEPPC") because that group is no longer active. Second, for the Recovery of Planning Costs (Section VIII), Tri-State's recovery of costs associated with both the Regional and Interregional Planning Processes differs from PSCo's recovery of costs.

deficiency, but is reasonable because Tri-State is not a Control Area and does not provide these ancillary services.

4. Schedules 7 and 8

Tri-State's proposed Rate Schedule 7, Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service and Rate Schedule 8, Non-Firm Point-to-Point Transmission Service, conform to the terms and conditions of the Commission's pro forma OATT, with three exceptions. First, Tri-State fills in the blanks for the applicable delivery charges by referencing the rate template on Tri-State's OASIS. The Commission has found this approach to be consistent with, or superior to, the pro forma OATT for other Transmission Providers.[22]

Second, Tri-State adds a charge for any taxes, fees and charges that are levied or assessed by any governmental or tribal authority based on the service rendered under Rate Schedules 7 and 8. In doing so, Tri-State does not limit the Transmission Customer's rights to oppose any governmental or tribal authority's determination that revenue-related taxes are applicable to the service provided under these schedules. Again, the Commission has found that additional charges in Rate Schedules 7 and 8 related to taxes and fees from governmental authorities are consistent with, or superior to, the pro forma OATT.[23] Therefore, the Commission should accept Tri-State's proposal in the instant filing.

Finally, Tri-State adds a charge for the recovery of a FERC Annual Charge Fee. The proposed revision permits Tri-State to recover the costs associated with FERC's regulatory oversight of Tri-State's transmission service from its transmission service customers, consistent with cost causation principles. Moreover, the Commission has found the inclusion of this charge in Rate Schedules 7 and 8 is an approach that is consistent with, or superior to, the pro forma OATT for other Transmission Providers.[24]

5. Rate Treatment for Failure to Comply with the OATT

In various sections of the pro forma OATT, the Commission included placeholder language for Transmission Providers to specify the rate treatment and the related terms and conditions for certain situations in which the Transmission Customer exceeds its firm and non-firm reserved capacity or uses transmission service that is not reserved or fails to comply with the actual terms and conditions in the OATT. Tri-State proposes to replace this placeholder language with the actual terms and conditions that will apply in each of these various situations. Specifically, in sections 13.7(c) and 14.5, Tri-State proposes an unreserved use penalty (in addition to the otherwise applicable charges) that is based on a rate that is equal to twice the applicable rate for Point-to-Point Transmission Services.[25] In section 28.6, Tri-State specifies the

[22] *See Xcel Energy Services, Inc.*, Letter Order, Docket ER16-1422 (Aug. 15, 2016) (approving filed re-baseline of Public Service Company of Colorado's OATT, including Schedules 7 and 8).

[23] *See Public Service Company of New Mexico*, Letter Order, Docket ER07-150-000 (Dec. 20, 2006) (approving similar language related to New Mexico taxes for PNM's Schedules 7 and 8).

[24] *See supra* n.22.

[25] *See* Order No. 890 at P 848.

appropriate charges and penalties if a Network Customer uses Network Integration Transmission Service to facilitate a wholesale sale that does not serve a Network Load; in section 30.4, Tri-State specifies the rate treatment if a Network Customer's schedule delivery exceeds its designated capacity; and in section 33.7, Tri-State specifies the rate treatment if a Network Customer fails to respond to load shedding or curtailment directives. Tri-State's proposed language is superior to the pro forma OATT because it sets forth the specific terms and conditions that Tri-State will apply in each of these situations.[26]

6. Reactive Supply and Voltage Control - Schedule 2

Schedule 2 of the Tri-State OATT provides the rates for Tri-State's provision of reactive power and voltage service from its generating facilities connected to the Tri-State Western Transmission System and reflect a cost-based annual revenue requirement of approximately $2.54 million. The revenue requirement is explained below and in the supporting testimony and exhibits of Mr. Robert C. Smith (Exhibit Nos. TS-008 to TS-023).

As discussed in Mr. Smith's testimony, Tri-State's revenue requirement reflects a cost-based value calculated in accordance with the Commission's AEP methodology. Tri-State's proposed cost-based revenue requirement in this filing reflects the Fixed Capability Component, which is designed to recover the ongoing cost to own, operate, and maintain that portion of Tri-State's total investment in the facilities that is properly attributed to the units' capability to produce reactive power. To develop the calculation, Mr. Smith first identified the fixed costs associated with four groups of equipment--the generator-exciter system; the generator step-up transformer ("GSU"); Accessory Electric Equipment; and remainder of investment ("Balance of Plant")--and then applied to each group an appropriate allocation factor that properly distinguishes real power from reactive power production so as to isolate the revenue requirements associated solely with reactive power production.

The resulting amount represents the total plant investment in reactive power capability, which is multiplied by a fixed charge rate that reflects the supplier's annual cost of owning, operating, and maintaining the reactive power investment in the plant. To calculate the fixed charged rate, Mr. Smith used a levelized annual carrying charge cost approach. Mr. Smith explains that the levelized fixed charge rate used to determine Tri-State's annual reactive revenue requirement contains the following components: operations and maintenance expense; administrative and general expense; property taxes; property insurance; working capital; depreciation expense; and return on investment.

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[26] *See South Central MCN, LLC*, 164 FERC ¶ 61,114 (2018) (approving OATT for GridLiance High Plains, LLC (formerly South Central MCN), inclusive of Sections 13.7, 14.5, 28.6, 30.4, and 33.7, containing similar language for the rate treatment when an Interconnection Customer fails to comply with the OATT). Pursuant to Order No. 890-A, Tri-State commits to submit a one-time compliance filing under Federal Power Act Section 206 proposing a methodology for distributing revenues from any collected unreserved use penalties to non-offending Transmission Customers. *See* Order No. 890-A at P 472, 475. Tri-State will submit its proposed methodology for Commission approval prior to the first distribution of any unreserved use penalty revenues. *See id.* at 472. Moreover, Tri-State will make an annual informational filing with the Commission that provides a summary of the penalty revenues Tri-State has received and distributed to Transmission Customers. *See id.*

Based on these calculations, Mr. Smith's testimony and exhibits support an annual cost-based revenue requirement for Tri-State's provision of reactive supply and voltage control service totaling $2,543,530.

7. Formula Rate Template and Protocols

Tri-State's Transmission Formula Rate Template and Implementation Protocols (collectively known as the "Formula Rate") were developed to annually determine Monthly Demand Charges for Network Integration Transmission Service (Attachment H), Point-to-Point transmission service (Schedules 7 and 8), and Scheduling System Control and Dispatch Service (Schedule 1) as provided for under its OATT.

As discussed in detail in the testimony and accompanying exhibits of Alfred W. Busbee (Exhibit Nos. TS-001 to TS-005), The proposed Transmission Formula Rate provides for the recovery of Tri-State's Annual Transmission Revenue Requirement ("ATRR") for its transmission facilities operated within Tri-State's service area in the Western Interconnect ("West Transmission Facilities"). The Formula Rate is substantively similar to the methodology, structure and rate design approved in Docket No. ER16-204 currently in the SPP Tariff. The Formula Rate calculates Tri-State's revenue requirement and rates for transmission services using a Weighted Average Cost of Capital ("WACC") return on depreciated net-plant (non-levelized) rate base plus operating expenses and applicable taxes. The Formula Rate along with the accompanying Implementation Protocols ("Protocols") are incorporated into Attachment M of the Tri-State Tariff.

Tri-State's Protocols describe the annual process of updating inputs to the Formula Rate Template to develop charges for the Rate Year as defined in the Protocols. Consistent with the Commission's approval in Docket No. ER16-204, Tri-State closely followed the Protocols of its Formula Rate currently in use in the SPP region. The Protocols set forth a defined schedule for updating rates, based on inputs from the prior fiscal year audited financial reports, a customer meeting to discuss the charges, an informational filing to the Commission, rights of customers to seek information concerning the charges, and if necessary, a process to challenge such charges. The Protocols ensure transparency of the Formula Rate development and the update process that will occur each year.

As Mr. Busbee explains, the Formula Rate develops rates that reflect the cost to provide transmission service over the West Transmission Facilities. A transmission customer taking service will be charged a rate based on the cost of those facilities. Based on YE 2018 audited financials, Tri-State's ATRR for its West Transmission Facilities is approximately $136 million.

The Monthly Demand Charge for Network Integration Transmission Service is calculated per Attachment H of the Tri-State Tariff by dividing Tri-State's ATRR by the 12-month average of the peak Transmission System Load (12CP) and dividing by 12.

Rates for Firm (Schedule 7) and Non-Firm (Schedule 8) Point-To-Point Transmission Service are similarly developed in the Formula Rate by dividing Tri-State's ATRR by its 12CP

and multiplied by the Reserved Capacity of the Transmission Service Reservation. Part II of the Tariff contains the terms and conditions governing Point-to-Point Transmission Service.

The charges associated Scheduling System Control and Dispatch Service (Schedule 1) are calculated by allocating appropriate expenses and plant investment using a Schedule 1 wages and salary allocator to determine a Schedule 1 ATRR. Like Network Integration and Point-to-Point Service, Schedule 1 charges are determined by dividing the (Schedule 1) ATRR by the 12CP and multiplying it by transmission customer's load. Schedule 1 rates recover the direct costs of Scheduling, System Control and Dispatch Services.

Mr. Busbee's testimony and supporting exhibits provide the initial determination of charges produced by the formula, based on Tri-State's 2018 RUS Form 12, which would be effective as of the sixtieth (60^{th}) day after the filing date hereof ("Effective Date") through September 30, 2020. Exhibit No. TS-003 to Mr. Busbee's testimony contains the populated version of the proposed Formula Rate Template, including source references, allocation factor calculations, and capital structure used in determining just and reasonable charges for service. Per Tri-State's Protocols, a workable populated Formula Rate Template with fully functional spreadsheets showing the calculation of the ATRR and the underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data inputs is publicly accessible on the Tri-State OASIS.

Tri-State respectfully submits that its Formula Rate and the initial charges produced thereunder are just and reasonable, and not unduly discriminatory or preferential. To the extent any waivers of the Commission's Regulations are required in conjunction with the cost support provided by Tri-State in connection with its initial rates, Tri-State respectfully requests such waivers.

8. Attachment H - Network Service ATRR

The pro forma Attachment H includes a blank for the Transmission Provider to provide its ATRR for Network Service and that the ATRR will remain effective until modified and approved by FERC. Tri-State proposes to replace this language in two respects. First, Tri-State includes a reference to its Formula Rate Template posted on Tri-State's OASIS for a calculation of its ATRR. The Commission has found this approach to be consistent with, or superior to, the pro forma OATT for other Transmission Providers.[27]

Second, similar to Schedules 7 and 8, Tri-State adds a charge for the recovery of a FERC Annual Charge Fee. As discussed above, the proposed revision permits Tri-State to recover the costs associated with FERC's regulatory oversight of Tri-State's transmission service from its transmission service customers, consistent with cost causation principles. Moreover, the Commission has found the inclusion of this charge in Attachment H is an approach that is consistent with, or superior to, the pro forma OATT for other Transmission Providers.[28]

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[27] *See supra* n.22 (approving Public Service Company of Colorado's Attachment H).

[28] *See id*.

9. Attachment C - Available Transfer Capability ("ATC") Methodology

The pro forma Attachment C directs the Transmission Provider to include detailed information about the methodology that it uses to calculate ATC on its system. Tri-State's proposed Attachment C provides the necessary detail required by Order No. 676-E[29] and Order No. 890.[30] Specifically, Tri-State describes the mathematical algorithms and methodologies that it uses to calculate each of the components (*i.e.*, Total Transfer Capability, Existing Transmission Commitments, Transmission Reliability Margin, Capacity Benefit Margin) that go into the calculation of ATC for both the operating and planning horizons on Tri-State's system. Tri-State also includes a process flow diagram to illustrate the steps taken to perform the calculation and determine the final ATC. Tri-State's approach for ATC calculation follows NERC's Rated System Path Methodology.[31] Accordingly, the Commission should find Tri-State's ATC methodology contained in Attachment C is consistent with or superior to the pro forma OATT.

10. Large Generator Interconnection Procedures (LGIP) and Large Generator Interconnection Agreement (LGIA)

Tri-State proposes a LGIP and LGIA that largely conform to the Commission's pro forma procedures and agreements issued under Order Nos. 2003,[32] 661,[33] 827,[34] and 842,[35] *et. seq*. However, as detailed below, Tri-State proposes certain modifications to specific provisions in the pro forma LGIP to facilitate the transition from Tri-State's existing Generator Interconnection Procedures ("GIP") to its new LGIP.

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29 *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,216, *reh'g denied*, Order No. 676-A, 116 FERC ¶ 61,255 (2006), *order on reh'g*, Order No. 676-B, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,246 (2007), *order on reh'g*, Order No. 676-C, III FERC Stats. & Regs., Regs. Preambles ¶ 31,274, *order on reh'g and clarification*, Order No. 676-D, 124 FERC ¶ 61,137 (2008), *final rule*, Order No. 676-E, 129 FERC ¶ 61,162 (2009); *final rule*, Order No. 676-F, 131 FERC ¶ 61,022 (2010); *final rule*, Order No. 676-G, 142 FERC ¶ 61,131 (2013), *final rule*, Order No. 676-H, 148 FERC ¶ 61,205 (2014).

30 *See supra* n.16.

31 *See* NERC Reliability Standards, MOD-029-2a.

32 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub. nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

33 *Interconnection for Wind Energy*, Order No. 661, 2001-2005 FERC Stats. & Regs., Regs. Preambles ¶ 31,186, *order on reh'g and clarification*, Order No. 661-A, 2001-2005 FERC Stats. & Regs., Regs. Preambles ¶ 31,198 (2005).

34 *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277, *order on clarification and reh'g*, 157 FERC ¶ 61,003 (2016).

35 *Essential Reliability Services and the Evolving Bulk-Power System-Primary Frequency Response*, Order No. 842, 162 FERC ¶ 61,128, *order on reh'g and clarification*, 164 FERC 61,138 (2018).

a. *Transition For Interconnection Requests Being Processed Under Tri-State's Existing Generator Interconnection Procedures*

The adoption of the pro forma LGIP will require a change to Tri-State's existing generator interconnection queue and queue approach. Specifically, like the pro forma LGIP, Tri-State's existing GIP assigns a Queue Position based upon the date and time of a valid Interconnection Request and processes such Interconnection Requests serially through the Interconnection System Impact Study stage. At the start of the Interconnection Facilities Study stage, however, an Interconnection Customer has a one-time right to defer the further processing of its Interconnection Request for a maximum of 18 months. Those Interconnection Customers that want to move forward with the Interconnection Facilities Study (or come out of deferral) are then processed in the order in which they execute their Interconnection Facilities Study Agreement. In other words, at the Interconnection Facilities Study stage, an Interconnection Request is assigned a new Queue Position and the Interconnection Facilities Study is performed based upon a first ready, first served approach.

Tri-State has 13 Interconnection Requests currently pending in deferral. The pro forma LGIP does not have a similar process for Interconnection Requests to go into deferral. If, by adoption of the pro forma LGIP, those Interconnection Requests are required to come out of deferral and be processed in the order of their original Queue Position, it would cause significant disruption for all the Interconnection Requests currently being studied under Tri-State's GIP. In particular, an Interconnection Request that comes out of deferral may have a higher original Queue Position than an Interconnection Request that is currently in the Interconnection Facilities Study stage. If so, the Interconnection Request that comes out of deferral that has a higher original Queue Position would in effect, "jump ahead" of those Interconnection Customers that did not elect to go into deferral, but instead proceeded to the Facilities Study stage. This may require a re-study for an Interconnection Request that already is in the midst of a Facilities Study, or even at the stage of signing a Generator Interconnection Agreement. This would also likely trigger re-studies for several other Interconnection Requests lower in the queue. Such a result would have significant costs, both financially and for the timely processing of those Interconnection Requests by Tri-State.

In order to mitigate this disruption and ensure a smooth and fair transition to the pro forma LGIP Queue Position procedures for existing Interconnection Requests, Tri-State proposes interim procedures for the processing of the Interconnection Requests currently being studied under Tri-State's GIP:

> First, all the Interconnection Requests in deferral will have the Transition Period (as defined in Section 5.1.2 of the LGIP) to notify Tri-State if they want to come out of deferral and have their Interconnection Request studied. If so, then the Interconnection Customer must execute an Interconnection Facilities Study Agreement. In accordance with the Tri-State's GIP, the Queue Position for the Interconnection Request that comes out of deferral and moves to a Facilities Study will be based on the order in which Tri-State receives an executed Interconnection Facilities Study Agreement. If the Interconnection Customer elects not to come out of deferral, then the Interconnection

Request will be withdrawn and any remaining deposit will be refunded to the Interconnection Customer, as appropriate.

Second, all other existing Interconnection Requests maintain their current Queue Position, but in an effort to ensure conformity with the pro forma LGIP, the Interconnection Requests must be processed and completed in accordance with the effective LGIP.

To implement these interim procedures, Tri-State proposes revisions to Section 5.1 of the pro forma LGIP and to add a definition for Tri-State's existing GIP. Specifically, Tri-State proposes the following provisions:

5.1 Queue Position for Pending Requests

5.1.1 Any Interconnection Customer assigned a Queue Position prior to the effective date of this LGIP shall retain that Queue Position *with the exceptions discussed below:*

5.1.1.1 If an Interconnection Study Agreement has not been executed as of the effective date of this LGIP, then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with this LGIP.

5.1.1.2 If an Interconnection Study Agreement has been executed prior to the effective date of this LGIP, such Interconnection Study shall be completed in accordance with the terms of such agreement. With respect to any remaining studies for which an Interconnection Customer has not signed an Interconnection Study Agreement prior to the effective date of the LGIP, ~~the Transmission Provider must offer~~ the Interconnection Customer *must go* ~~the option of either continuing under the Transmission Provider's existing interconnection study process or going~~ forward with the completion of the necessary Interconnection Studies (for which it does not have a signed Interconnection Study Agreement) in accordance with this LGIP. *Interconnection Customers in deferral under the Transmission Provider's GIP have the Transition Period (as defined in Section 5.1.2 of this LGIP) to notify the Transmission Provider of their request to come out of deferral; otherwise, the Interconnection Customers will be withdrawn from the Interconnection Study process and any remaining deposit will be refunded, as appropriate. Interconnection Customers electing to come out of deferral and electing to execute an Interconnection Facilities Study Agreement will be assigned a Queue Position for the*

Interconnection Facilities Study and have their Interconnection Request processed based on the order in which Transmission Provider receives the executed Interconnection Facilities Study Agreement.

Section 1 - Definitions

Generator Interconnection Procedures *(GIP) shall mean Transmission Provider's Generator Interconnection Procedures prior to the effective date of the Standard Large Generator Interconnection Procedures (LGIP).*

Further, Tri-State proposes to modify Section 5.1.1.3 of the pro forma LGIP and to add a definition for Tri-State's existing Generator Interconnection Agreement ("GIA"). The proposed changes are necessary to recognize that, until the instant filing becomes effective, Tri-State is non-jurisdictional, and therefore, a GIA would not be submitted to FERC for approval. That said, GIAs executed prior to the effective date of the LGIP should also be considered grandfathered. Specifically, Tri-State proposes the following changes:

5.1.1.3 If a~~n~~ ~~L~~GIA has been ~~submitted to FERC for approval~~*executed* before the effective date of the LGIP, then the ~~L~~GIA would be grandfathered.

Section 1 - Definitions

Generator Interconnection Agreement *(GIA) shall mean Transmission Provider's Generator Interconnection Agreement prior to the effective date of the Standard Large Generator Interconnection Agreement (LGIA).*

Finally, Tri-State proposes to add a new Section 5.3. Under Tri-State's GIP, an Interconnection Customer may elect to interconnect its Generating Facility either as a Network Resource or as a non-Network Resource. These types of interconnection service will also need to transition over to the types of interconnection service under the LGIP. In particular, Tri-State's Network Resource service under the GIP will be Network Resource Interconnection Service under the LGIP and Tri-State's non-Network Resource under the GIP will be Energy Resource Interconnection Service under the LGIP. To implement this change, Tri-State proposes the following provisions:

5.3 Type of Interconnection Services

5.3.1 Any Interconnection Customer that submitted an Interconnection Request to be studied as a Network Resource under the Transmission Provider's GIP will be deemed to have requested Network Resource Interconnection Service in accordance with this LGIP.

5.3.2 Any Interconnection Customer that submitted an Interconnection Request to be studied as a non-Network Resource under the Transmission

> *Provider's GIP will be deemed to have requested Energy Resource Interconnection Service in accordance with this LGIP.*

As explained above, Tri-State's proposed changes to the pro forma LGIP are both necessary due to the unique circumstances presented by Tri-State's GIP and critical for Tri-State's transition to the pro forma LGIP. Therefore, the Commission should approve these changes as superior to the pro forma LGIP.

b. Order Nos. 845 and 845-A Compliance

In Order Nos. 845[36] and 845-A[37], the Commission adopted reforms to the pro forma LGIP and LGIA to generally improve certainty for interconnection customers, promote more informed interconnection decisions, and enhance the interconnection process. Tri-State does not propose any revisions to its LGIP and LGIA to incorporate the provisions of Order Nos. 845 and 845-A in the instant filing. Rather, Tri-State intends to make a separate filing to comply with Order Nos. 845 and 845-A in the next few days. Therefore, Tri-State requests that the Commission not reject the instant filing as deficient, but consider the instant filing in conjunction with Tri-State's soon-to-be filed Order No. 845 compliance filing.

D. Description of Concurrent Filings

As noted above, Tri-State is concurrently filing in separate dockets several other initial rate schedules and related contracts. Specifically, Tri-State is also filing on this day: (i) an initial filing of its Wholesale Electric Service Contracts (Rate Schedules FERC No. 1 through No. 43); (ii) a stated rate tariff for the full requirements service that Tri-State provides its Members (FERC Electric Tariff Volume No. 1); and (iii) an Application for Authority to Charge Market-based Rates and a market-based rate tariff (FERC Electric Tariff Volume No. 3).[38] Tri-State's wholly-owned subsidiary, Thermo Cogeneration Partnership, L.P., is also concurrently filing in a separate docket its own Application for Authority to Charge Market-based Rates and a market-based rate tariff.

E. Names and Addresses of the Those to Whom a Copy of the Tariff Has Been Mailed

Copies of this filing have been mailed to each of Tri-State's Members and to the state regulatory commissions of Colorado, New Mexico, Nebraska, and Wyoming. Addresses for each of these entities are attached hereto as Attachment A.

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[36] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 (2018) ("Order No. 845").

[37] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845-A, 166 FERC ¶ 61,137 (2019) ("Order No. 845-A").

[38] Tri-State's wholly-owned subsidiary, Thermo Cogeneration Partnership, L.P., is also concurrently filing in a separate docket its own Application for Authority to Charge Market-based Rates and a market-based rate tariff.

IV. REQUEST FOR WAIVERS

Pursuant to the Commission's authority under FERC Rule 101(e), Tri-State respectfully seeks waiver of any unintentional noncompliance with applicable rules and regulations as may be necessary for the Commission to accept Tri-State's FERC Electric Tariff Volume No. 2 for filing as requested herein.

V. CONCLUSION

Wherefore, Tri-State respectfully requests that the Commission accept Tri-State's FERC Electric Tariff Volume No. 2 for filing without suspension or condition, to be effective 60 days after the date of this filing.

Respectfully submitted,

/s/ David. S. Shaffer

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Counsel for
Tri-State Generation and Transmission Association, Inc.

Dated July 23, 2019

ATTACHMENT A

ADDRESSES OF ENTITIES
RECEIVING COPIES OF THIS FILING

State Utility Commissions

Colorado Public Utilities Commission
1560 Broadway, Suite 250, Denver, CO 80202
Main Number 303-894-2000
Fax Number 303-894-2065

Nebraska Public Service Commission
1200 N Street, Suite 300
Lincoln, Nebraska 68508
Main Number 402-471-3101

New Mexico Public Regulation Commission
1120 Paseo De Peralta, PERA Building
P.O. Box 1269, Santa Fe, NM 87504
Main Number 1-888-427-5772

Wyoming Public Service Commission
2515 Warren Avenue, Suite 300
Cheyenne WY 82002
Main Number 307-777-7427
Fax Number 307-777-5700

Members of Tri-State Generation and Transmission Association, Inc.

Big Horn Rural Electric Company
208 South 5th Street
PO Box 270
Basin, Wyoming 82410
Main Number 307-568-2419
Fax Number 307-568-2402

Carbon Power & Light, Inc.
100 E. Willow Street
PO Box 579
Saratoga, Wyoming 82331
Main Number 307-326-5206
Fax Number 307-326-5934

Central New Mexico Electric Cooperative, Inc.
810 1st Street
Moriarty, New Mexico 87035
Receiving: 202 E. Martinez Road
Moriarty, New Mexico 87035
Main Number 505-832-4483
Fax Number 505-832-0946

Chimney Rock Public Power District
128 West 8th Street
PO Box 608
Bayard, Nebraska 69334
Main Number 308-586-1824
Fax Number 308-586-2511

Columbus Electric Cooperative, Inc.
900 N. Gold
PO Box 631
Deming, New Mexico 88031
Main Number 575-546-8838
Fax Number 575-546-3128

Continental Divide Electric Cooperative, Inc.
200 E. High Street
PO Box 1087
Grants, New Mexico 87020
Main Number 505-285-6656
Fax Number 505-287-2234

Delta-Montrose Electric Association
11925 6300 Road Montrose, Colorado 81401
PO Box 910 Montrose, Colorado 81402
Main Number 877-687-3632
Fax Number 970-240-6801

Empire Electric Association, Inc.
801 N. Broadway
PO Box K
Cortez, Colorado 81321
Main Number 970-565-4444
Fax Number 970-564-4401

Garland Light & Power Company
755 Highway 14
Powell, Wyoming 82435
Main Number 307-754-2881
Fax Number 307-754-5320

Gunnison County Electric Association, Inc.
37250 West Highway 50
PO Box 180
Gunnison, Colorado 81230
Main Number 970-641-3520
Fax Number 970-641-7333

High Plains Power, Inc.
1775 East Monroe
PO Box 713
Riverton, Wyoming 82501
Main Number 307-856-9426
Fax Number 307-856-4207

High West Energy, Inc.
6270 County Road 212
PO Box 519
Pine Bluffs, Wyoming 82082
Main Number 307-245-3261
Fax Number 307-245-9292

Jemez Mountains Electric Cooperative, Inc.
Chama Highway
PO Box 128 Espanola, New Mexico 87532
19368 S.R. 84/285 Hernandez, New Mexico 87537
Main Number 505-753-2105
Fax Number 505-753-6958

K.C. Electric Association, Inc.
422 Third Avenue
PO Box 8
Hugo, Colorado 80821
Main Number 719-743-2431
Fax Number 719-743-2396

La Plata Electric Association, Inc.
45 Stewart Street Durango, CO 81303
PO Box 2750 Durango, CO 81302
Main Number 970-247-5786
Fax Number 970-247-2674

The Midwest Electric Cooperative Corporation
104 Washington Ave
PO Box 970
Grant, Nebraska 97140
Main Number 308-352-4356
Fax Number 308-352-4957

Mora-San Miguel Electric Cooperative, Inc.
501 State Highway 518
PO Box 240
Mora, New Mexico 87732
Main Number 575-387-2205
Fax Number 575-387-5975

Morgan County Rural Electric Association
734 Barlow Road
PO Box 738
Fort Morgan, Colorado 80701
Main Number 970-867-5688
Fax Number 970-867-3277

Mountain Parks Electric, Inc.
321 West Agate Avenue
PO Box 170
Granby, Colorado 80446
Main Number 970-887-3378
Fax Number 970-887-3996

Mountain View Electric Association, Inc.
1655 5th Street
PO Box 1600
Limon, Colorado 80828
Main Number 719-775-2681
Fax Number 719-775-9513

Niobrara Electric Association
3951 U.S. Highway 20
PO Box 697
Lusk, Wyoming 82225
Main Number 307-334-3221
Fax Number 307-334-2620

Northern Rio Arriba Electric Cooperative, Inc.
1135 Camino Escondido
PO Box 217
Chama, New Mexico 87520
Main Number 575-756-2181

Northwest Rural Public Power District
5613 State Highway 87
PO Box 249
Hay Springs, Nebraska 69347
Main Number 308-635-4445
Fax Number 308-635-4448

Otero County Electric Cooperative, Inc.
404 Burro Avenue
PO Box 227
Cloudcroft, New Mexico 88317
Main Number 575-682-2521
Fax Number 575-682-3109

Panhandle Rural Electric Membership Association
251 Brayton Road
PO Box 677
Alliance, Nebraska 69301
Main Number 308-762-1311
Fax Number 308-762-5750

Poudre Valley Rural Electric Association, Inc.
7642 REA Parkway Fort Collins, Colorado 80528
PO Box 272550 Fort Collins, Colorado 80527
Main Number 800-432-1012
Fax Number 970-226-2123

Roosevelt Public Power District
190038 Yale Avenue Scottsbluff, Nebraska 69361
PO Box 97 Mitchell, Nebraska 69357
Main Number 308-635-2424
Fax Number 308-635-0632

San Isabel Electric Association, Inc.
781 E. Industrial Blvd.
Pueblo West, Colorado 81007
Main Number 719-547-2160
Fax Number 719-547-2229

San Luis Valley Rural Electric Cooperative, Inc.
3625 U.S. Highway 160 West
PO Box 3625
Monte Vista, Colorado 81144
Main Number 719-852-3538
Fax Number 719-852-6655

San Miguel Power Association, Inc.
170 W. 10th Avenue
PO Box 817
Nucla, Colorado 81424
Main Number 970-864-7311
Fax Number 970-864-7257

Sangre de Cristo Electric Association, Inc.
29780 North U.S. Highway 24
PO Box 2013
Buena Vista, Colorado 81211
Main Number 719-395-2412
Fax Number 719-395-8742

Sierra Electric Cooperative Inc.
610 Highway 195
PO Box 290
Elephant Butte, New Mexico 87935
Main Number 575-744-5231
Fax Number 575-744-5819

Socorro Electric Cooperative, Inc.
215 E. Manzanares
PO Box H
Socorro, New Mexico 87801
Main Number 575-835-0560
Fax Number 575-835-4449

Southwest Colorado Power Association
27850 Harris Road
PO Box 521
La Junta, Colorado 81050
Main Number 719-384-2551
Fax Number 719-384-7320

Southwestern Electric Cooperative, Inc.
216 Main Street
PO Box 369
Clayton, New Mexico 88415
Main Number 575-374-2451
Fax Number 575-374-2030

Springer Electric Cooperative, Inc.
408 Maxwell Avenue
PO Box 698
Springer, New Mexico 87747
Main Number 575-483-2421
Fax Number 575-483-2692

United Power, Inc.
500 Cooperative Way Brighton, Colorado 80603
PO Box 929 Brighton, Colorado 80601
Main Number 303-659-0551
Fax Number 303-659-2172

Wheat Belt Public Power District
11306 Road 32
PO Box 177
Sydney, Nebraska 69162
Main Number 308-254-5871
Fax Number 308-254-2384

Wheatland Rural Electric Association, Inc.
2154 South Street
Wheatland, Wyoming 82201
Main Number 307-322-2125
Fax Number 307-322-5340

White River Electric Association Inc.
233 6th Street
PO Box 958
Meeker, Colorado 81641
Main Number 970-878-5041
Fax Number 970-878-5766

Wyrulec Company
3978 U.S. Highway 26/85 Torrington, Wyoming 82240
PO Box 359 Lingle, Wyoming 82223
Main Number 307-837-2225
Fax Number 307-837-2115

Y-W Electric Association, Inc.
250 Main Avenue
PO Box Y
Akron, Colorado 80720
Main Number 970-345-2291
Fax Number 970-345-2154

ATTACHMENT B

TRI-STATE'S FERC ELECTRIC TARIFF
VOLUME NO. 2

(Submitted in rtf format in compliance with Order No. 714)

ATTACHMENT C

TABLE OF DEVIATIONS FROM PRO FORMA OATT

Summary of Deviations from Pro Forma OATT

Pro Forma OATT Section, Schedule or Attachment Reference	**Description of Deviation**	**Reason for Revision**
OATT		
Section 1.12	Definition of Effective Date added.	Added to provide clarity on the deadlines and due dates included in the OATT.
Section 1.49	Definition of Tariff added.	Added to allow reference to Tariff in various sections of the OATT.
Section 1.52	Definition of Transmission Provider modified to state that Tri-State is the Transmission Provider	Modified to clarify that Tri-State is the Transmission Provider in the OATT.
Section 2.1	Replaced "effective date of the Tariff" with "Effective Date".	Modified to refer to defined term and to clarify the effective date of the Tariff.
Section 2.2	Replaced the bracketed language with a reference to the Effective Date of the Tariff.	Modified to clarify the date by which a Transmission Customer's rollover rights become effective by referencing the effective date of the Tariff.
Section 4	Replaced "tariff" with "Tariff".	Modified to refer to defined term.
Section 11	Creditworthiness section is modified to reflect: (i) Transmission Provider may employ reasonable credit review procedures; and (ii) Transmission Customer may be required to provide and maintain an unconditional and irrevocable letter of credit or other form of security during the term of the Service Agreement.	Adding language to specify the Transmission Provider's creditworthiness requirements. The added language provides a general description of Tri-State's creditworthiness procedures consistent with the procedures adopted in Attachment L.
Section 13.3	Replaced the bracketed language with "Effective Date".	Modified to clarify the effective date of the Tariff.

Section 13.7	Classification of Firm Transmission Service section is modified to replace placeholder language with details on the rate treatment if Transmission Customer exceeds its firm reserved capacity or uses service it has not reserved.	See explanation in the transmittal letter, section III.C.5.
Section 13.8	Deleted the bracketed language for increments of scheduled capacity and energy.	Modified to clarify the increments for scheduling of capacity and energy under the OATT.
Section 14.1	Replace “Purchaser” with “purchaser”	Modified to fix typographical error. “Purchaser” is not a defined term in the OATT.
Section 14.3	Replaced the bracketed language with “Effective Date”.	Modified to clarify the effective date of the Tariff.
Section 14.5	Classification of Non-Firm Point-to-Point Transmission Service section is modified to replace placeholder language with details on the rate treatment if Transmission Customer exceeds its non-firm reserved capacity or uses service it has not reserved.	See explanation in the transmittal letter, section III.C.5.
Section 14.6	Deleted the bracketed language for increments of scheduled energy.	Modified to clarify the increments for scheduling of energy under the OATT.
Section 15.7	Real Power Losses section modified to add the Real Power Loss factor.	See explanation in the transmittal letter, section III.C.2.
Section 17.1	Application section modified to (1) delete the bracketed language and add contact information for Tri-State; and (2) delete language about submitting an application prior to implementation of Transmission Provider’s OASIS.	Modified to provide the contact information for Tri-State and to recognize that Tri-State has an OASIS.
Section 17.2	Completed Application section modified to add NERC Identification.	Modified to reflect that Tri-State uses the NERC Identification to activate a

		Transmission Customer so they can purchase transmission and tag their transactions.
Section 18.1	Application section modified to delete language about submitting an application prior to implementation of Transmission Provider’s OASIS.	Modified to recognize that Tri-State has an OASIS.
Section 18.2	Completed Application section modified to add NERC Identification.	Modified to reflect that Tri-State uses the NERC Identification to activate a Transmission Customer so they can purchase transmission and tag their transactions.
Section 28.5	Real Power Losses section modified to add the Real Power Loss factor.	See explanation in the transmittal letter, section III.C.2.
Section 28.6	Restrictions on Use of Service section is modified to replace placeholder language with details on the rate treatment if Network Customer uses its network service to not serve its network load.	See explanation in the transmittal letter, section III.C.5.
Section 29.2	Application Procedures section modified to (1) delete language about submitting an application prior to implementation of Transmission Provider’s OASIS; and (2) add NERC Identification.	Modified to recognize that Tri-State has an OASIS and that Tri-State uses the NERC Identification to activate a Transmission Customer so they can purchase transmission and tag their transactions.
Section 30.4	Operation of Network Resources modified to replace placeholder language with details on the rate treatment if Network Customer’s scheduled delivery exceeds its designated capacity	See explanation in the transmittal letter, section III.C.5.
Section 30.9	Replaced the bracketed language with “May 14, 2007”.	Modified to clarify the effective date of Order No. 890.

Section 33.7	System Reliability section modified to replace placeholder language with details on the rate treatment if Network Customer Network Customer fails to respond to load shedding or curtailment directives.	See explanation in the transmittal letter, section III.C.5.
Schedule 1	Modified to include reference to Tri-State's Formula Rate Template.	See explanation in the transmittal letter, section III.C.7.
Schedule 2	Modified to include Schedule 2 charges.	See explanation in the transmittal letter, section III.C.6.
Schedule 7	Modified to incorporate (1) reference to Tri-State's Formula Rate Template; (2) a charge for Gross Receipts Tax, where applicable; and (3) a charge for FERC Annual Charge Fee.	See explanation in the transmittal letter, section III.C.4.
Schedule 8	Modified to incorporate (1) reference to Tri-State's Formula Rate Template; (2) a charge for Gross Receipts Tax, where applicable; and (3) a charge for FERC Annual Charge Fee.	See explanation in the transmittal letter, section III.C.4.
Attachment A	Added Tri-State as Transmission Provider	Filled in blanks for Tri-State as Transmission Provider.
Attachment A-1	Added Tri-State as Transmission Provider	Filled in blanks for Tri-State as Transmission Provider.
Attachment B	Added Tri-State as Transmission Provider	Filled in blanks for Tri-State as Transmission Provider.
Attachment C	Modified to incorporate information about Tri-State's ATC calculation methodology.	See explanation in the transmittal letter, section III.C.9.
Attachment D	Replaced placeholder language with Tri-State's methodology for completing a System Impact Study.	Tri-State inserted its methodology for completing a System Impact Study.
Attachment E	Index of Point-to-Point Transmission Service Customers modified to add reference to Tri-State's EQR filings.	Tri-State inserted link to EQR filings for a list of its Point-to-Point Transmission Service Customers.

Attachment F	Replaced placeholder language with Tri-State's form of agreement for Network Integration Transmission Service.	Tri-State inserted its form of agreement for Network Integration Transmission Service.
Attachment G	Replaced placeholder language with Tri-State's Network Operating Agreement.	Modified to include Tri-State's Network Operating Agreement.
Attachment H	Modified to incorporate (1) reference to Tri-State's Formula Rate Template; and (2) a charge for FERC Annual Charge Fee.	See explanation in the transmittal letter, section III.C.8.
Attachment I	Index of Network Integration Transmission Service Customers modified to add reference to Tri-State's EQR filings.	Tri-State inserted link to EQR filings for a list of its Network Integration Transmission Service Customers.
Attachment J	Replaced placeholder language with Tri-State's procedures for addressing parallel flows.	Tri-State inserted its procedures for addressing parallel flows.
Attachment K	Modified to incorporate description of Tri-State's transmission planning process.	See explanation in the transmittal letter, section III.C.1.
Attachment L	Modified to incorporate information about Tri-State's Creditworthiness Procedures.	Tri-State inserted its Creditworthiness Procedures.
Attachment M	Transmission Formula Rate Template and Protocols added.	See explanation in the transmittal letter, section III.C.7.
Attachment N	Standard Large Generator Interconnection Procedures (LGIP), including Standard Large Generator Interconnection Agreement (LGIA) added.	See explanation in the transmittal letter, section III.C.10.
Attachment O	Standard Small Generator Interconnection Procedures (SGIP), including Standard Small Generator Interconnection Agreement (SGIA) added.	Tri-State inserted its SGIP and SGIA.

LGIP		
Section 1	Definition of Applicable Reliability Council modified to replace “reliability council” with “”Regional Entity, as defined by Section 215 of the Federal Power Act”.	Added to clarify that the Regional Entity is the appropriate Applicable Reliability Council.
Section 1	Definition of Generator Interconnection Agreement (GIA) added.	Added to allow references to Tri-State’s GIA in the LGIP.
Section 1	Definition of Generator Interconnection Procedures (GIP) added.	Added to allow references to Tri-State’s GIP in the LGIP.
Section 1	Definition of Good Utility Practice modified to add “including those practices required by Federal Power Act section 215(a)(4).”	Added to clarify that Good Utility Practice shall include compliance with NERC Reliability Standards and is consistent with the definition in the OATT.
Section 1	Definition of Transmission Provider modified to state that Tri-State is the Transmission Provider	Modified to clarify that Tri-State is the Transmission Provider in the LGIP
Section 5.1.1	Modified to reflect the process for transitioning from Tri-State’s GIP to the LGIP.	See explanation in the transmittal letter, section III.C.10.a.
Section 5.1.1.2	Modified to reflect the process for transitioning from Tri-State’s GIP to the LGIP.	See explanation in the transmittal letter, section III.C.10.a.
Section 5.1.1.3	Modified to reflect that a GIA will be grandfathered if executed before the effective date of the LGIP.	See explanation in the transmittal letter, section III.C.10.a.
Section 5.3	Type of Interconnection Services section added.	See explanation in the transmittal letter, section III.C.10.a.

LGIA		
Introductory Paragraph	Added “Tri-State Generation and Transmission Association, Inc. a cooperative corporation organized and existing under the laws of the State of Colorado” as the Transmission Provider.	Added to reflect Tri-State as the Transmission Provider under the LGIA.
Article 1	Definition of Applicable Reliability Council modified to replace “reliability council” with “”Regional Entity, as defined by Section 215 of the Federal Power Act”.	Added to clarify that the Regional Entity is the appropriate Applicable Reliability Council.
Article 1	Definition of Good Utility Practice modified to add “including those practices required by Federal Power Act section 215(a)(4).”	Added to clarify that Good Utility Practice shall include compliance with NERC Reliability Standards and is consistent with the definition in the OATT.
Article 1	Definition of NERC modified to replace “Council” with “Corporation”.	Modified to reflect the correct name for NERC.
Article 1	Definition of Transmission Provider modified to state that Tri-State is the Transmission Provider.	Modified to clarify that Tri-State is the Transmission Provider in the LGIA.
Article 5.11	Transmission Provider’s Interconnection Facilities Construction section modified to delete “the following” and the placeholder for “[include appropriate drawings and relay diagrams]”.	Modified to remove placeholder and state that Transmission Provider will provide information on its Interconnection Facilities, upon request.

SGIP		
Attachment 1	Definition of Good Utility Practice modified to add “including those practices required by Federal Power Act section 215(a)(4).”	Added to clarify that Good Utility Practice shall include compliance with NERC Reliability Standards and is consistent with the definition in the OATT.
SGIA		
Introductory Paragraph	Added “Tri-State Generation and Transmission Association, Inc. a cooperative corporation organized and existing under the laws of the State of Colorado” as the Transmission Provider	Added to reflect Tri-State as the Transmission Provider under the SGIA.
Article 1.5.7	Capitalized “agreement” to reflect use of the defined term “Agreement” in introductory paragraph	Modified to use the appropriate defined term in the SGIA.
Article 12.10	Replace “governmental authorities” with “Governmental Authorities”	Modified to use the appropriate defined term in the SGIA.
Attachment 1	Definition of Good Utility Practice modified to add “including those practices required by Federal Power Act section 215(a)(4).”	Added to clarify that Good Utility Practice shall include compliance with NERC Reliability Standards and is consistent with the definition in the OATT.
Attachment 1	Definition of Transmission Provider modified to add Tri-State Generation and Transmission Association, Inc.	Modified to reflect Tri-State as the Transmission Provider under the SGIA.

ATTACHMENT D

PREPARED DIRECT TESTIMONY OF ALFRED W. BUSBEE

Exhibit No. TS-001

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tri-State Generation & Transmission Association, Inc.	**Docket No. ER19-____-000**

PREPARED DIRECT TESTIMONY AND EXHIBITS
OF
Alfred W. Busbee

On Behalf of

TRI-STATE GENERATION & TRANSMISSION ASSOCIATION, INC.

Formulary Transmission Rates in non-RTO areas of the Tri-State service territory

July 23, 2019

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Exhibit No. TS – 004	Summary of differences between SPP Formula Rate Template and West Formula Rate Template
Exhibit No. TS – 005	Eligible Facilities included in West Formula Rate

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tri-State Generation and Transmission Association, Inc | Docket No. ER19-____-000

Prepared Direct Testimony and Exhibits
Of
Alfred W. Busbee

On Behalf of

Tri-State Generation and Transmission Association, Inc.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Alfred W. Busbee. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067.

Q. By whom are you employed and in what capacity?

A. I am a Project Manager at GDS Associates, Inc. ("GDS"), a multi-disciplinary engineering and consulting firm that serves primarily electric, gas and water utilities. I have been employed by GDS since 2015.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Arts degree in Economics from the University of Georgia in 1982. I have 36 years of professional work experience including 29 years of regulated utility experience that includes regulatory and government affairs. My experience and knowledge span the functional areas of finance, plant accounting, and field operations. My background provides the necessary experience and expertise to support regulatory filings before state utility commissions and Federal regulatory agencies, including the Federal Energy Regulatory Commission ("FERC" or the "Commission").

Prior to joining GDS, I was employed from 2012 to 2015 by Southwest Power Pool, Inc. ("SPP") in the Regulatory Policy group where my responsibilities included regulatory policy analysis. As a result, I am very familiar with SPP's Open Access Transmission Tariff ("SPP Tariff") and well-versed in Independent System Operator ("ISO") and Regional Transmission Organization ("RTO") operations and the impacts their policy determinations have on affected stakeholder groups. While employed by SPP, I participated in the preparation and submission to FERC of cost-of-service filings by SPP on behalf of its members. My involvement included assisting in the preparation and the review of testimony supporting the appropriateness of the cost-of-service studies for both investor-owned utility rate cases and non-jurisdictional utility filings where cost allocation and revenue requirements were at issue. I am familiar with electric utility cost allocation methods, Generally Accepted Accounting Principles, and FERC and National Association of Regulatory Utility Commissioners general cost-of-service and ratemaking principles. My primary area of expertise is FERC regulatory matters involving wholesale transmission rates and services. I have been involved in numerous proceedings (both cost-of-service and formula rate cases) in which the proper level of transmission revenue requirements was at issue. I previously submitted testimony in Docket No. ER16-1546, ER18-2450, and ER19-1137 regarding determination of Annual Transmission Revenue Requirements.

I serve as a voting member on the SPP Regional Tariff Working Group ("RTWG") representing East Texas Electric Cooperative, Inc. The RTWG is the gateway for all tariff revisions. A thorough understanding of the SPP Tariff is a prerequisite for

voting members and needed to engage in issues brought before this stakeholder working group. The RTWG is responsible for development, recommendation, overall implementation, and oversight of all revisions to the SPP Tariff. The RTWG also advises SPP Staff on regulatory or implementation issues not specifically covered by the SPP Tariff or issues where there may be conflict or differing interpretations of the SPP Tariff. The RTWG provides policy input to the SPP Markets and Operations Policy Committee and Board of Directors and its committees, if requested.

My background and qualifications are included as Exhibit No. TS -002 to this testimony.

Q. What are your duties and responsibilities at GDS Associates?

A. My primary responsibilities involve providing rate and regulatory consulting services related to electric utility industry matters including rate design, cost of service and related revenue requirements, transmission revenue requirements and formula rates.

Q. On whose behalf are you presenting testimony in this proceeding?

A. I am presenting this testimony on behalf of the Tri-State Generation & Transmission Association, Inc. ("Tri-State").

II. <u>PURPOSE OF TESTIMONY AND BACKGROUND</u>

Q. What is the purpose of your testimony?

A. GDS was retained by Tri-State to assist with development of its Transmission Formula Rate Template and Implementation Protocols (collectively known as the

"Formula Rate") for purposes of recovering the Tri-State's eligible transmission Annual Transmission Revenue Requirements ("ATRRs") for its transmission facilities operated within Tri-State's service area in the Western Interconnect ("West Transmission Facilities"). The West Transmission Facilities are located outside the geographic area of a FERC Regional Transmission Operator (RTO).

Tri-State currently has a Formula Rate for its transmission facilities within the footprint of the SPP. Approved in Docket No. ER16-204[1], the Formula Rate used in SPP ("SPP Formula Rate") is included in Attachment H of the SPP Tariff, Sixth Revised Volume No. 1[2]. The proposed Formula Rate for Tri-State's West Transmission Facilities ("West Formula Rate") is substantively the same in structure and operation to the SPP Formula Rate approved by the Commission.

Q. Please describe Tri-State and its operations.

A. Tri-State was incorporated in Colorado in 1952, is a consumer/member-owned rural wholesale electric power generation and transmission cooperative operating on a not-for-profit basis that provides electricity at wholesale to its member distribution systems ("Members"), and has its principal place of business in Westminster, Colorado. In addition to owning certain electric generation facilities, Tri-State owns and operates approximately 5,668 miles of transmission facilities over which Tri-State transmits electricity to its forty three (43) Members, which in

[1] See Tri-Sate formula template at http://opsportal.spp.org/OASIS/Directory/Member%20Related%20Postings

[2] http://app.spp.org/etariff_viewer.html

turn provide electric distribution service to their approximately 1.3million customers in Colorado, Nebraska, New Mexico and Wyoming. Tri-State's transmission facilities are located in these four states, and Tri-State does not sell or distribute power at retail.

Pursuant to Section 201(f) of the FPA, Tri-State currently is not regulated under Part II of the FPA as a "public utility" (as defined under Section 201(e) of the FPA) because each of its forty-three (43) Members is (i) an electric distribution cooperative association that receives financing from the United States Department of Agriculture Rural Utilities Service ("RUS") and/or sells less than 4,000,000 MWh of electricity per year, or (ii) is a public power district (i.e., a political subdivision of the State of Nebraska).

Tri-State expects to admit one or more new members/owners of Tri-State on or about 60 days from the date of filing hereof ("New Member"). New Member will not be an electric cooperative or a governmental entity and will not directly or indirectly be wholly-owned by an electric cooperative or a governmental entity. Thus, Tri-State will become a public utility regulated under Part II of the FPA on or about 60 days from the date of filing hereof, because it will no longer be wholly owned directly or indirectly by entities that are states/political subdivisions of a state or by electric cooperatives which have RUS debt or sell less than 4,000,000 MWh of electricity per year.

Q. What is the relationship between Tri-State and its members?

A. Tri-State is owned by its 43 Members. Those Members are in-turn owned by their retail consumers. Tri-State and the Members are not-for-profit entities since all

margins generated from them are assigned to the owners and ultimately used in the business or given back as capital credits over time.

Q. What exhibits are you sponsoring in addition to your testimony?

A. I sponsor the following exhibits in addition to this testimony identified as Exhibit No. TS - 001 Direct Testimony of Alfred W. Busbee

- Exhibit No. TS – 002 Curriculum Vitae of Alfred W. Busbee
- Exhibit No. TS – 003 Populated West Formula Rate Template
- Exhibit No. TS-004 Summary of differences between SPP Formula Rate Template and West Formula Rate Template
- Exhibit No. TS – 005 Eligible Facilities included in West Formula Rate

III. <u>TRI-STATE WEST TRANSMISSION FACILITIES</u>

Q. Describe Tri-State's transmission assets.

A. Tri-State owns (wholly or jointly) or has maintenance responsibilities for approximately 5,665 miles of transmission line across Colorado, Nebraska, New Mexico and Wyoming. The transmission assets operate in both major electrical grids of the United States and include a direct current ("DC") inter-tie, as well as transmission lines and associated equipment at voltages of 69 kV to 345 kV.

Q. Are Tri-State West Transmission Facilities currently included in Tri-State's ATRR collected under the SPP Tariff?

A. No. Only those Tri-State transmission facilities that are physically located in the SPP region that qualify under Attachment AI of the SPP Tariff are included in the SPP Formula Rate and reflected in SPP rates. Tri-State operates in both the Western and Eastern Interconnections and only those assets Tri-State owns in the Eastern Interconnect, primarily in Nebraska and a few in Colorado, are under SPP

functional control and included in the SPP Formula Rate approved in Docket No. ER16-204. The Commission approved transfer of functional control of these facilities in Opinion No. 562[3], and denied rehearing in Opinion No. 562A[4].

Q. How did Tri-State determine which transmission assets to include in the West Transmission Facility rate base in its West Formula Rate?

A. Tri-State used criteria similar to that applied in its SPP Formula Rate. Tri-State performed an analysis using the criteria modeled on Attachment AI of the SPP Tariff to qualify Tri-State's West Transmission Facilities for inclusion in rate base as described in more detail below.

Q. Please describe the West Transmission Facilities that Tri-State has included in rate base that form the basis of Tri-State's ATRR to be included in the West Formula Rate.

A. The West Transmission Facilities are listed and included as Exhibit No. TS-005. The West Transmission Facilities include approximately 5,612 miles of transmission circuits, together with the associated substations, reactive power resources, and equipment, operating at 100KV or greater[5]. Tri-State transferred to the functional control of SPP and recovers only costs for those facilities and

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[3] Southwest Power Pool, Inc., Opinion No. 562,163 FERC ¶ 61,109 (2018), reh'g denied, Opinion No. 562-A, 166 FERC ¶ 61,019 (2019). appeal pending, Case No. 19-1553 (8th Cir. 2019).

[4] 166 FERC ¶ 61,019

[5] Attachment AI of the SPP Tariff specifies the operating voltage of Eligible Transmission Facilities be a minimum of 69KV. Tri-State has included in rate base transmission facilities operation at or above 100KV consistent with North American Electric Reliability Corporation ("NERC") Bulk Electric System Definition Reference Document, Version 3, August 2018.

equipment in the Eastern Interconnection that meet the definition of "Transmission Facilities" set forth in Attachment AI of the SPP Tariff.

Q. What operational criteria did Tri-State use to qualify the West Transmission Facilities for inclusion in its West Formula Rate?

A. Tri-State included transmission facilities that meet the following criteria: All existing non-radial power lines, substations, and associated facilities, operated at 100 kV or above, plus all radial lines and associated facilities operated at or above 100 kV that serve two or more Eligible Customers not Affiliates of each other. For the application of this criterion, "open loops" are radial lines. Additionally, at such time an existing radial is incorporated into a looped transmission circuit that existing radial would be eligible for inclusion in rates on the same basis as the remainder of the facilities in the loop.

Q. Did Tri-State apply the same criteria to its West Transmission Facilities as it did for its SPP facilities?

A. Except for the increase in operating voltage criteria (i.e., 100KV and greater), Tri-State applied criteria modeled on Attachment AI of the SPP Tariff to qualify its West Transmission Facilities included in the proposed West Formula Rate. Tri-State believes it is consistent to apply the same criteria for purposes of identifying Eligible Transmission Facilities (as defined in Attachment M of the Tri-State Open Access Transmission Tariff) across the entire Tri-State system. Since the SPP criteria is used for part of the Tri-State system and is a FERC approved criterion in the SPP Tariff, Tri-State believes consistent use across its system would put

transmission customers on either side of the interconnect on the same footing as far as the cost of "Eligible" Transmission Facilities.

IV. TRANSMISSION COST-OF-SERVICE

A. FORMULA RATE

Q. Please explain the general structure of the SPP Formula Rate that was approved by the Commission in Docket No. ER16-204.

A. The SPP Formula Rate provides for the recovery of Tri-State's Annual Transmission Revenue Requirement ("ATRRs") for its transmission facility investment. Approved in Docket No. ER16-204, the SPP Formula Rate calculates Tri-State's revenue requirement for transmission services using a Weighted Average Cost of Capital ("WACC") return on depreciated net-plant (non-levelized) rate base plus operating expenses and applicable taxes. The SPP Formula Rate along with the accompanying Implementation Protocols ("Protocols") are incorporated into Attachment H of the SPP Tariff. Consistent with the Protocols, Tri-State's historical calendar test year coincides with its fiscal year. There is no need for an annual true-up of its rates because they are developed using final, audited historic financial data and no projections.

Q. Is Tri-State's West Formula Rate substantively similar to the structure of the SPP Formula Rate?

A. Yes. Tri-State's West Formula Rate was developed to annually determine charges for Network Integration Transmission Service (Monthly Demand Charge), Point-

to-Point transmission service (Schedules 7 and 8), and the Scheduling System Control and Dispatch Service (Schedule 1) as provided for under Tri-State's proposed Open Access Transmission Tariff ("Tri-State Tariff"). The ATRR calculation methodology and formula rate structure are substantively similar to Tri-State's SPP Formula Rate. The proposed West Formula Rate relies on the same plant and expense allocation methodology and return calculations as used in its SPP Formula Rate. It was necessary that Tri-State make modifications to remove SPP specific requirements and its RTO participation. Other changes reflect corrections to formula errors, source references, and various "clean up" items. Most of the changes are ministerial in nature. Material changes are discussed below in Determination of Tri-State's ATRR. A summary of the differences is included in Exhibit No. TS - 004.

Q. Does Tri-State's proposed West Formula Rate provide for corrections if an error is discovered within a reasonable time?

A. Yes. Section III. D.3 of the Protocols in the West Formula Rate specifically state:

> If Tri-State makes a correction to a Mistake in its financial information during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in accordance with the SPP Tariff. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as arithmetic or computational errors. Mistakes shall not include matters involving exercise

of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

Q. Please describe the West Formula Rate for the West Transmission Facilities.

A. Consistent with the SPP Formula Rate, the proposed West Formula Rate for the West Transmission Facilities calculates a revenue requirement for transmission services using a WACC return on depreciated net-plant (non-levelized) rate base, plus operating expenses, and applicable taxes. The West Formula Rate is incorporated into Attachment M of the proposed Tri-State Tariff in this filing. Tri-State proposes essentially the same Protocols using a historical calendar test year that coincides with its fiscal year. As with the SPP Formula Rate, there is no need for an annual true-up of its rates because they are developed using final audited historic financial data and no projections. For example, based on 2018 fiscal year data, the applicable Rate Year extends from October 1, 2019 through September 30, 2020.

Unlike the SPP Formula Rate, Tri-State is proposing the Rate Year as October 1 through September 30. This proposed deviation from the SPP Rate Year (July to June) is for administrative ease in managing multiple Formula Rate updates and stakeholder review processes of the respective Formula Rates. In addition, to concur with the requested Effective Date of this filing Tri-State requests that the initial Rate Year to be effective as of the sixtieth (60th) day after the filing date hereof ("Effective Date") through September 30, 2020.

B. DETERMINATION OF TRI-STATE'S ATRR

Q. Please describe the West Formula Rate design and development.

A. The SPP Formula Rate and West Formula Rate are substantively identical in structure; references and descriptions are generally applicable to both. Included as Exhibit No. TS – 003 is a populated version of the West Formula Rate. The West Formula Rate is a Microsoft Excel-based workbook made up of 25 integrated spreadsheet tabs indexed on the first tab as listed below. Worksheets A – V are used in the calculation of the transmission revenue requirement. The Formula Rate is based on Tri-State's actual costs drawn from audited company records including the RUS Form 12[6]. The Formula Rate calculates a "historic" revenue requirement for transmission service using Tri-State's West Transmission Facilities.

[6] Effective November 5, 2014, Tri-State was no longer subject to the accounting and reporting rules and regulations of the United States Department of Agriculture, RUS. However, Tri-State continues to follow the RUS Uniform System of Accounts prescribed for Class A and B Electric Utilities that utilize a similar chart of accounts found in the FERC Uniform System of Accounts. While Tri-State will be required to produce and file with the Commission an annual FERC Form 1, Tri-State in the interim will produce a Form 12. Beginning October 1, 2020 Tri-State will utilize the requisite FERC Form 1.

Index

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

INDEX

Data:

Page	Item	Description
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2	Summary	Summary of Total ATRR Revenue Requirement
3	Schedule 1	Schedule 1 Revenue Requirement
4	Worksheet A	Rate Base
5	Worksheet B	O&M, Depreciation, and Return Expenses
6	Worksheet C	Return
7	Worksheet D	Load
8	Worksheet E	Allocation Factors
9	Worksheet F	Inputs
10	Worksheet G	O&M
11	Worksheet H	Network Credits
12	Worksheet I	Depreciation Rates
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23	Worksheet T	Retirement Work in Progress
24	Worksheet U	Eligible Transmission Substations
25	Worksheet V	Eligible Transmission Lines
		= Shaded cells denotes manual input

A. Worksheet A develops the transmission rate base using the average of the beginning and end of year average of transmission plant balances. Worksheet A shows the allocation or direct investment of transmission plant applicable to West

Transmission Facilities. Intangible plant is allocated based on wages and salaries. No production plant investment or expenses are allocated in the West Formula Rate.

All transmission station plant (Accounts 350-353) is allocated to the transmission plant category based on the analysis of Eligible Transmission Facilities performed by Tri-State. The transmission lines (Accounts 354-359) are allocated based on the actual costs associated with Eligible Transmission Facilities. Then a ratio of Eligible Transmission lines gross plant divided by the total Other Transmission Plant was created. The ratio was used in the formula to allocate cost in Accounts 354-359 as well as other related accounts.

No distribution plant is allocated in the West Formula Rate General and Intangible plant is allocated to transmission based on wages and salaries. The wage and wage overheads of all O&M accounts are considered in the development of the wages and salaries allocation factor. Accounts 106 and 107, which include completed construction not classified and construction work in progress, are summarized in Worksheet Q and Worksheet R of the supporting workpapers. The allocation of the remaining plant accounts on Worksheet A are based on plant allocation factors described above.

Finally, a cash working capital allowance based on a lag of 45 days is included as well as prepayments and materials and supplies balances are included in Tri-State's Rate Base.

Q. Please describe how Tri-State calculates its expenses and return component associated with the operation of the West Transmission Facilities.

A. Worksheet B summarizes detail from the following schedules in determining its Revenue Requirement before the application of revenue credits. Each worksheet utilizes the company's YE 2018 audited financial records as reported on its RUS Form 12. The resulting Revenue Requirement is linked to the Summary tab where appropriate Revenue Credits are applied to determine Tri-State's Net ATRR.

1. Worksheet G - O&M Input,
2. Worksheet P - Account 575 / 576 Expenses,
3. Worksheet F – Inputs,
4. Worksheet S - Regulatory and Commission Expenses,
5. Worksheet L - Depreciation Expense and,
6. Worksheet C - Return

Q. Are the depreciation rates used by Tri-State as shown in Worksheet L approved by the Commission?

A. Yes. These are the same depreciation rates approved in Docket No. ER18-985 and may not be changed absent a filing or Commission action pursuant to Section 205 or 206 of the Federal Power Act.

Q. Is the Return on Equity ("ROE") shown in Worksheet C approved by the Commission?

A. Yes. The West Formula Rate calculates a revenue requirement for transmission service that includes a WACC return on a depreciated net-plant (non-levelized) rate base plus operating expenses and taxes, which is the fundamental formula used in most transmission cost-of-service rates. The return is based the ROE approved in Docket No. ER16-204, excluding the RTO adder, and may not be changed absent

a filing or Commission action pursuant to Section 205 or 206 of the Federal Power Act.

Q What Capitalization Ratios and ROE were approved by the Commission in Tri-State's SPP Formula Rate?

A. The Commission approved an equity ratio floor of 35.24% for Tri-State and an equity ratio ceiling of 68.86%. If Tri-State's equity level is below 35.24%, the formula uses 35.24% as the equity level. If Tri-State's equity level is between 35.34% and 68.86%, the formula uses the actual equity level, and if Tri-State's equity level is above 68.86% the formula uses an equity ceiling of 68.86% instead of actual.

Q Is Tri-State proposing to a change to the Capitalization Ratio used in the West Formula Rate?

A. Only to the extent that Tri-State is proposing to include debt related to "Notes Payable" in the capital structure. This proposed change will tend to lower the overall Rate of Return as notes payable has a lower embedded cost than long-term debt and equity. In the test year, notes payable made up about 5% of total Tri-State capitalization at an embedded cost rate of 2.76%.

Q. Please describe the transmission service rates and charges developed in the West Formula Rate and summarized on the Rates tab.

A. In addition to the Monthly Demand Charge associated with Network Integration Service, the Formula Rate calculates rates for Schedule 1 – Scheduling System Control and Dispatch Service, and Schedule 7 and 8 - Point to Point Service

Q. How is the Monthly Demand Charge associated with Network Integration Service determined in the West Formula Rate?

A. The Monthly Demand Charge for Network Integration Transmission Service is calculated per Attachment H of the Tri-State Tariff by dividing the Tri-State's ATRR by the 12-month average of the peak Transmission System Load (12CP) and dividing by 12. Part III of the Tri-State Tariff contains the terms and conditions governing Network Integration Transmission Service.

Q. How are Rates for Firm (Schedule 7) and Non-Firm Point-To-Point Transmission Service (Schedule 8) determined in the Formula Rate?

A. The rates for Point to Point Rates are developed in the West Formula Rate in the same manner as the Monthly Demand Charge, that is, by dividing the Tri-State's ATRR by its 12CP. However, unlike the Monthly Demand Charge, the rate is based on the Reserved Capacity of the Transmission Service Reservation. Part II of the Tri-State Tariff contains the terms and conditions governing Point to Point Transmission Service.

Q. Please describe the charges associated Scheduling System Control and Dispatch Service (Schedule 1)

A. Schedule 1 rates recover the direct costs of Scheduling, System Control and Dispatch Services. The rate associated Scheduling System Control and Dispatch Service (Schedule 1) is calculated by allocating appropriate expenses and plant investment using a Schedule 1 wages and salary allocator to determine a Schedule 1 ATRR and then dividing the ATRR by the 12CP. Customer charges are assessed by multiplying the Schedule 1 rate times the transmission customer's load.

Q. Does the West Formula Rate include other transmission service charges that are not developed in the West Formula Rate?

A. Yes. The West Formula Rate includes on the Rate tab charges for Schedule 2 - Reactive Supply and Voltage Control (VAR Support) and the FERC Annual Charge. These rates are assessed to transmission customers but are inputs not derived from the West Formula Rate. See the testimony of Mr. Robert Smith supporting the development of Schedule 2 rates. The FERC Annual Charge is a pass through of annual charges assessed by the FERC.

Q. Please explain why the proposed West Formula Rate is just and reasonable.

A. The proposed West Formula Rate yields just and reasonable revenue requirements and is supported by audited financial data currently reflected in Tri-State's RUS Form 12 data. The Tri-State bulk electric system comprising the West Transmission Facilities are similarly situated to the Tri-State assets under the SPP RTO functional control and the proposed rate design and West Formula Rate are substantively similar to the SPP Formula Rate previously approved by the FERC.

C. IMPLEMENTATION PROTOCOLS

Q. Describe the Tri-State Implementation Protocols.

A. The Protocols incorporated into the West Formula Rate, included in Attachment M of the proposed Tri-State Tariff, provide instructions relating to the annual update of the West Formula Rate. The Protocols prescribe the process Tri-State will use to annually update the ATRR. The Protocols specify Tri-State's obligations and responsibilities to its Customers and other Interested Parties (as defined in the

Protocols) to provide information to enable stakeholders to validate the Formula Rate calculations and resulting rates. Tri-State must follow the instructions and time lines specified in the Protocols to calculate its ATRR and the rates associated with Network Integration Transmission Service, Point-to-Point Transmission Service, and Ancillary Services for use of its West Transmission Facilities.

Q. Please describe the timelines included the Implementation Protocols.

A. Tri-State's annual schedule begins when the usage and financial data is available from the RUS Form 12 or applicable financial reporting documents. An initial posting of the populated West Formula Rate will occur on July 15th followed by an annual meeting with the Interested Parties no later than August 4th. The Interested Parties have a sixty-day period from the date on which the populated West Formula Rate is posted to review and make inquiries. Any Informal Challenges must be made by September 14th in order to be resolved in the current Rate Year. The new ATRR will go into effect on October 1st[7] and continue through September 30th of the following year. Every effort will be made to review and reconcile timely challenges so that they may be included in the next Rate Year. If this cannot be done, then a reconciliation will be done in the subsequent Rate Year. An informational filing will be made each October 15th. The procedures for Interested Parties to make and resolve Informal Challenges are addressed the Protocols. Likewise, the procedures for making and resolving Formal Challenges

[7] The Rate Year as defined in the Protocols is October 1 through September 30. Tri State is proposing the initial Rate Year begin to be effective as of the sixtieth (60th) day after the filing date hereof ("Effective Date") through September 30, 2020 to concur with the requested Effective Date of the filing.

are defined specifically in the Protocols. The definition section of the Protocols addresses these terms.

Q. Please comment on Tri-State's timeline in which 60 days are allocated for Interested Parties to review the information and make Informal Challenges.

A. Tri-State's Protocols describe a straightforward procedure because Tri-State's West Formula Rate are based on a historical year rather than a projected or forward-looking year. By using actual data, Tri-State eliminates the need to review the forecast process and other items such as the construction program since all historical information is recorded and audited by independent accountants. In addition, there are 60 days for Interested Parties to process the information before the final Informal Challenge is due on September 14, although challenges may be made up to the end of the review period, which may or may not give Tri-State time to respond prior to the Final Posting date. In total, Interested Parties have approximately 60 days of review, which is adequate and consistent with what was approved in SPP Formula Rate.

Q. Please describe Tri-State's annual informational filing.

A. Each year, by October 15th, Tri-State will make an Informational Filing with the Commission, including the input data, calculations, and detailed determination of Tri-State's ATRR. The Informational Filing will also inform the Commission of any on-going disputes under the Formal Challenges procedures in the Protocols.

Q. In your opinion, is Tri-State's proposed West Formula Rate just and reasonable?

Q. Yes.

Q. Does this conclude your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tri-State Generation and Transmission Association, Inc.	))))	**Docket No. ER19-___-000**

AFFIDAVIT OF ALFRED W. BUSBEE

Alfred W. Busbee, being first duly sworn, deposes and says that he is the Alfred W. Busbee referred to in the foregoing direct testimony, filed on behalf of Tri-State Generation and Transmission Association, Inc., that he has read such testimony, and is familiar with the contents thereof and that the answers therein are true and correct to the best of his knowledge, information, and belief.

Alfred W. Busbee
Alfred W. Busbee

Subscribed and sworn to before me this 15th day of July 2019, by self, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

LISA D WILSON NOTARY PUBLIC EXP. 01/08/2023 BARTOW COUNTY, GEORGIA

Lisa Wilson
Notary Public

Commission Expires on: January 8, 2023

GDS Associates, Inc
ENGINEERS & CONSULTANTS

ALFRED W. BUSBEE

Project Manager

EDUCATION

Bachelor of Arts Economics, University of Georgia, 1982

EXPERIENCE

Mr. Busbee has 29 years of regulated utility experience that includes regulatory and government affairs. His experience spans the functional areas of finance, plant accounting, and field operations. His background provides the necessary experience and expertise to support his expert testimony in regulatory filings before state utility commissions and the Federal Energy Regulatory Commission. He is very familiar with the Regional Transmission Organizations in the United States and well versed in ISO and RTO operations and its stakeholder groups. His experience includes expert testimony regarding regulatory policy, tariff management, rate case preparation, management of discovery, and settlement negotiations.

Mr. Busbee has a high level of understanding of the power system and associated transmission system issues. His project management skills serve his clients in completion of complex processes of clear scope, milestones and timeline development, delegation of tasks, closure requirements and resource management.

Since joining GDS, Mr. Busbee has been nominated and serves as a voting member on the Southwest Power Pool ('SPP") Regional Tariff Working Group. The Regional Tariff Working Group (RTWG) is responsible for development, recommendation, overall implementation and oversight of SPP's Open Access Transmission Tariff (Tariff). The RTWG will further advise the SPP Staff on regulatory or implementation issues not specifically covered by the Tariff or issues where there may be conflict or differing interpretations of the Tariff. The RTWG provides policy input to the Markets and Operations Policy Committee (MOPC) and Board of Directors (BOD) and its committees, if requested.

GDS Associates, Inc., Marietta, GA,
Project Manager

Southwest Power Pool (SPP), Little Rock, AR
Regulatory Analyst III

Arkansas Alliance of Boys and Girls Clubs, Conway, AR
Alliance Director

Brent Stevenson Associates, Little Rock, AR
Director - Business Development / Contract Lobbyist

CenturyLink, Jacksonville, AR
Manager – Government Relations, Arkansas/Oklahoma

Alltel Communications, Inc. (acquired by Verizon), Little Rock, AR
Staff Manager - Wholesale Services
Manager - IntraLATA Toll Products
Manager - State Regulatory Matters
Sr. Analyst - State Regulatory Matters

Florida Public Service Commission, Tallahassee, FL
Regulatory Analyst, Division of Communication

SPECIFIC PRIOR EXPERIENCE

Southwest Power Pool (SPP), Little Rock, AR

- Worked closely with internal and external legal departments. Applied advanced teamwork and resource delegation skills to accomplish complex regulatory processes in a team environment, including preparation of strategies, goals, objectives and working papers for SPP working groups. Coordinated stakeholder-drive processes using group expertise. Coordinated and monitored administration of SPP's tariff(s) to ensure compliance with requirements and obligations of the tariff.

- Coordinated and monitored administration of SPP's tariff(s) to ensure compliance with requirements and obligations of the tariff. Lead analyst on FERC dockets involving adding new Transmission Owners in SPP Region, Formula Rate Updates, Stated Rate Filings, and transmission policy determinations. Developed and delivered presentations outlining analysis results and SPP policy positions to state and federal regulators, customers and SPP committees and working groups. Communicated with transmission customers, member representatives and state and federal regulators to discuss SPP policy initiatives, regional transmission tariff provisions and proposed modifications, and state and federal regulatory activities.

Alltel Communications, Inc. (acquired by Verizon), Little Rock, AR

- Expert witness in numerous arbitration proceedings in multiple jurisdictions regarding the Telecommunications Act of 1996. Supervised professional staff in preparation of contracts and attachments.

- Point of contact for regulatory agency in assigned states. Supervised professional staff in analysis of commission orders, preparation of filings, interrogatories and comments, and monitoring of earnings. Cross functional team member for development and implementation of regulatory policy in Ohio, Pennsylvania, and New York.

- Accountable for regulatory approval of tariff and other filings by the eight state region. Structured settlements and resolved issues affecting the industry with inter-company committees.

Florida Public Service Commission, Tallahassee, FL

- Researched public utility economic and regulatory policy and developed analysis and recommendations for Commission consideration. Prepared written recommendations and verbally presented to the Commissioners. Subject to cross examination regarding Staff recommendations. Participated in rate cases, generic investigations, and compliance audits.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

INDEX

Data: Year Ending December 31, 2018

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Point-to-Point, Schedule 1, and Schedule 2 Transmission Rates
Data: Year Ending December 31, 2018

A	B	C		D
Line	Description	Reference		Allocated Amount
1	**Annual Transmission Revenue Requirement**			
2	Net Annual Transmission Revenue Requirement	Summary, Line 12, Col H	$	135,939,937
3				
4	**System Load (kW)**			
5	12 Month Average Transmission System Peak	Worksheet D, Line 14, Col E		2,206,753
6				
7	**Point-to-Point Transmission Rates - $/kW**			
8	$ / kW-Year	(D2/ D5)	$	61.602
9	$ / kW-Month	(D8 / 12 months)	$	5.133
10	$ / kW per Week	(D8 / 52 weeks)	$	1.185
11	$ / kW per Day	(D8 / 312 days)	$	0.197
12	mills per kWh--Firm and ONPEAK non-firm	(D8 / 4,160 hours * 1,000)	$	14.808
13	mills per kWh--OFFPEAK non-firm	(D8 / 8,760 hours * 1,000)	$	7.032
14	**Schedule 1 - Annual Revenue Requirement**			
15	Net Schedule 1 Revenue Requirement	Schedule 1, Line 18, Col H		$9,992,445
16				
17	**System Load (kW)**			
18	12 Month Average Transmission System Peak	Worksheet D, Line 14, Col E		2,206,753
19				
20	**Schedule 1 Rates - $/kW**			
21	$ / kW-Year	(D15 / D18)	$	4.528
22	$ / kW-Month	(D21 / 12 months)	$	0.377
23	$ / kW per Week	(D21 / 52 weeks)	$	0.087
24	$ / kW per Day	(D21 / 365 days)	$	0.012
25	mills per kWh	(D21 / 8,760 hours * 1,000)	$	0.517
26	**Schedule 2 - Reactive Supply and Voltage Control (VAR Support)**			
27	Net Schedule 2 Revenue Requirement	[Input Initial Filing No. Here]	$	2,543,530
28				
29	**System Load (kW)**			
30	12 Month Average Transmission System Peak	[Input Initial Filing No. Here]		2,332,915
31				
32	**Schedule 2 Rates - $/kW** (Note: A)			
33	$ / kW-Year	(D27 / D30)	$	1.09028
34	$ / kW-Month	(D33 / 12 months)	$	0.09086
35	$ / kW per Week	(D33/ 52 weeks)	$	0.02097
36	$ / kW per Day	(D33 / 365 days)	$	0.00299
37	mills per kWh	(D33 / 8,760 hours * 1,000)	$	0.12446
	A.) These rates are fixed and cannot be changed absent authorization from FERC via a Section 205 or 206 filing.			
38	**FERC Annual Charge**			
39	FERC's annual charge per MWh is established by the Commission annually, and is assessed to the Transmission Owner, and is passed through to the Transmission Customers.			/MWh
40				

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Summary of Total ATRR Revenue Requirement
Data: Year Ending December 31, 2018

A	B	C	D	E	F	G	H
Line	**Account**	**Description**	**Reference**	**Total Company**	**Allocation Factor**	**Allocation %**	**Transmission**
1		**A. Gross Revenue Requirement for Network Service**					
2		Transmission Costs	Worksheet B, Line 38, Col I				$ 149,025,153
3		Revenue Credits-Operating					
4	454	Rental Income	Worksheet M, Line 24, Col D and F	$ 3,233,533	Direct		$ 670,118
5	456	Other Electric Revenue - Administrative Fee -TSR	Worksheet M, Line 25, Col D and F	$ -	Direct		$ -
6	456	Revenues from Transmission of Electricity of Others including ST Firm & Non-Firm	Worksheet M, Line 26, Col D	$ 13,214,079	Direct		$ 9,397,106
7	456	Other Electric Revenue - GFAs	Worksheet M, Line 27, Col F	$ 3,017,993	Direct 100	100.000%	$ 3,017,993
8	456	Other Electric Revenue	Worksheet M, Line 28, Col D	$ 1,657,959	Direct Zero	0.000%	$ -
9		Revenue Credits-Operating	Subtotal	$ 21,123,563			$ 13,085,217
10		Reconciliation Adjustments to ATRR	Worksheet J, Line 6, Col J				$ -
11		Reconciliation Adjustments to ATRR - Other	Worksheet J, Line 12, Col J				$ -
12		Net Annual Transmission Revenue Requirement	Line 2 - Line 9 + Lines 10 & 11				$ 135,939,937

Tri-State Generation & Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Schedule 1 Revenue Requirement
Data: Year Ending December 31, 2018

A Line	B Account	C Description	D Reference	E Total Company	F Allocation Factor	G Allocation %	H Total Schedule 1
1	**DIRECT EXPENSE AMOUNTS**						
2	561	Load Dispatching	Worksheet G, Line 2, Col F	$9,445,684	T-Tran Plant	72.62%	$6,859,860
3	**ASSOCIATED LOAD DISPATCHING COSTS**						
4		**Expenses**					
5		Total Company Customer Accounting Expense	Worksheet B, Line 19, Col F	$756,212	T-Wage2	4.30%	$32,546
6		Total Company Administrative & General Expenses	Worksheet B, Line 28, Col F	$28,798,925	T-Wage2	4.30%	$1,239,444
7		Total Company General Plant Depreciation Expense	Worksheet F, Line 135, Col F	$26,224,645	T-Wage2	4.30%	$1,128,652
8		Total Company Intangible Plant Amortization Expense	Worksheet F, Line 146, Col F	$3,783,162	T-Wage2	4.30%	$162,819
9		**Total Expenses**	Sum Lines 5 thru 8	$59,562,945			$2,563,461
10		**Return on General & Intangible Plant**					
11		Total Company Net Intangible Plant in Service	Worksheet A, Line 35, Col F	$63,575,987	T-Wage2	4.30%	$2,736,174
12		Total Company Net General Plant in Service	Worksheet A, Line 39, Col F	$153,345,129	T-Wage2	4.30%	$6,599,645
13		Total General & Intangible Plant	Sum Lines 11 and 12	$216,921,116			$9,335,819
14		Weighted Rate of Return	Worksheet C, Line 5, Col K				6.10%
15		Return on General & Intangible Plant	Line 13 * Line 14				$569,124
16		**Total Associated Load Dispatching Costs**	Line 9 + Line 15				$3,132,585
17	**SCHEDULE 1 REVENUE REQUIREMENT**						
18		**Net Schedule 1 Revenue Requirement for Zone**	Sum Lines 2 and 16				**$9,992,445**
19		Load Dispatching Wages and Salaries	Worksheet E, Line 3, Col D	$6,494,098	T-Tran Plant	72.62%	$4,716,292
20		Total Wages and Salaries	Worksheet E, Line 8, Col D	$109,584,747	Direct100	100.00%	$109,584,747
21		Schedule 1 Wages & Salaries Allocator	Line 19 / Line 20			**T-Wage2 =**	**4.30%**

Tri-State Generation and Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE
Rate Base
Data: Year Ending December 31, 2018

A	B	C	D	E	F	G	H	I
Line	Description	Reference	Beginning of Year	End of Year	Total Company	Allocation Factor	Allocation %	Transmission
1	**Plant in Service**							
2	301-303 Total Intangible Plant	Worksheet F Line 72, Col D thru F	$ 143,815,271	$ 144,127,021	$ 143,971,146	T-Wage Allocation	31.881%	$ 45,899,615
3	310 Steam Production Plant	Worksheet F Line 73, Col D thru F	$ 1,957,298,716	$ 2,001,741,701	$ 1,979,520,209	Direct Zero	0.000%	$ -
4	320 Nuclear Production Plant	Worksheet F Line 74, Col D thru F	$ -	$ -	$ -	Direct Zero	0.000%	$ -
5	330 Hydro Production Plant	Worksheet F Line 75, Col D thru F	$ -	$ -	$ -	Direct Zero	0.000%	$ -
6	340 Other Production Plant	Worksheet F Line 76, Col D thru F	$ 283,327,691	$ 284,231,267	$ 283,779,479	Direct Zero	0.000%	$ -
7	Total Production Plant	Subtotal	$ 2,240,626,407	$ 2,285,972,968	$ 2,263,299,688			$ -
8	350 Land and Land Rights	Worksheet F Line 78, Col D thru F	$ 127,713,237	$ 131,239,316	$ 129,476,277	T-Tran Lines	84.271%	$ 109,111,457
9	352 Structures and Improvements	Worksheet F Line 79, Col D thru F	$ 46,184,559	$ 54,560,378	$ 50,372,469	T-Tran Stations	59.989%	$ 30,217,705
10	353 Station Equipment	Worksheet F Line 80, Col D thru F	$ 535,910,825	$ 569,873,188	$ 552,892,007	T-Tran Stations	59.989%	$ 331,671,801
11	354 thru 359.1 Other Transmission Plant	Worksheet F Line 81, Col D thru F	$ 524,894,264	$ 525,096,113	$ 524,995,189	T-Tran Lines	84.271%	$ 442,420,738
12	Transmission Plant	Subtotal	$ 1,234,702,885	$ 1,280,768,995	$ 1,257,735,940			$ 913,421,700
13	360 Land and Land Rights	Worksheet F Line 83, Col D thru F	$ 1,553,591	$ 1,553,591	$ 1,553,591	Direct Zero	0.000%	$ -
14	361 Structures and Improvements	Worksheet F Line 84, Col D thru F	$ 9,573,419	$ 9,830,550	$ 9,701,985	Direct Zero	0.000%	$ -
15	362 Station Equipment	Worksheet F Line 85, Col D thru F	$ 82,788,360	$ 84,532,517	$ 83,660,439	Direct Zero	0.000%	$ -
16	363-374 Other Distribution Plant	Worksheet F Line 86, Col D thru F	$ -	$ -	$ -	Direct Zero	0.000%	$ -
17	Total Distribution Plant	Subtotal	$ 93,915,370	$ 95,916,658	$ 94,916,014			$ -
18	380-386 RTO/ISO Plant	Worksheet F, Line 88 Col F	$ -	$ -	$ -	T-Tran Plant	72.624%	$ -
19	389 thru 399.1 Total General Plant	Worksheet F, Line 89 Col F	$ 466,525,796	$ 463,757,674	$ 465,141,735	T-Wages	31.881%	$ 148,292,399
20	106 Completed Construction Not Classified	Worksheet F Line 94, Col D thru F and Worksheet Q Line 1 Col I	$ 274,138,335	$ 292,683,250	$ 283,410,793	Direct		$ 94,876,195
21	Gross Electric Plant in Service	Subtotal	$ 4,453,724,064	$ 4,563,226,566	$ 4,508,475,315			$ 1,202,489,909
22	**Accumulated Depreciation**							
23	108.1 Depr Rsv. of Steam Plant	Worksheet F, Line 101 Col D thru F	$ 1,023,235,337	$ 1,060,707,871	$ 1,041,971,604	Direct Zero	0.000%	$ -
24	108.2 Depr Rsv. of Nuclear Plant	Worksheet F, Line 102 Col D thru F	$ -	$ -	$ -	Direct Zero	0.000%	$ -
25	108.3 Depr Rsv. of Hydraulic Plant	Worksheet F, Line 103 Col D thru F	$ -	$ -	$ -	Direct Zero	0.000%	$ -
26	108.4 Depr Rsv. of Other Prod Plant	Worksheet F, Line 104 Col D thru F	$ 113,924,205	$ 116,120,844	$ 115,022,525	Direct Zero	0.000%	$ -
27	Total Production Reserve	Sum	$ 1,137,159,542	$ 1,176,828,715	$ 1,156,994,129			$ -
28	108.5 Depreciation of Transmission Plant	Worksheet F Line 105, Col D thru F and (Worksheet V Cols J and L Line 10 + Worksheet U Cols J and L Line 10)/2	$ 506,575,074	$ 524,819,021	$ 515,697,048	Direct		$ 378,533,990
29	108.6 Depreciation of Distribution Plant	Worksheet F, Line 106 Col D thru F	$ 40,075,858	$ 39,374,613	$ 39,725,236	Direct Zero	0.000%	$ -
30	108.7 Depreciation of General Plant	Worksheet F, Line 107 Col D thru F	$ 307,474,092	$ 316,119,121	$ 311,796,607	T-Wage Allocation	31.881%	$ 99,404,253
31	108.8 Retirement Work in Progress	Worksheet F Line 108, Col D thru F and Worksheet T Line 1 Col J	$ (1,067,648)	$ (1,978,451)	$ (1,523,050)	Direct		$ (1,288,839)
32	111 Amort of Electric Plant in Service	Worksheet F, Line 109 Col D thru F	$ 78,965,898	$ 81,824,420	$ 80,395,159	T-Wage Allocation	31.881%	$ 25,630,878
33	Total Accumulated Depreciation	Sum	$ 2,069,182,816	$ 2,136,987,439	$ 2,103,085,128			$ 502,280,283
34	**Total Net Plant in Service**							
35	301-303 Net Total Intangible Plant	Line 2 - Line 32	$ 64,849,373	$ 62,302,601	$ 63,575,987			$ 20,268,737

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Rate Base
Data: Year Ending December 31, 2018

A	B	C	D	E	F	G	H	I
Line	**Description**	**Reference**	**Beginning of Year**	**End of Year**	**Total Company**	**Allocation Factor**	**Allocation %**	**Transmission**
36	Net Production Plant	Line 7 - Line 27	$ 1,103,466,865	$ 1,109,144,253	$ 1,106,305,559			$ -
37	Net Transmission Plant	Line 12 + Line 18 - Line 28	$ 728,127,811	$ 755,949,974	$ 742,038,893			$ 534,887,710
38	Net Distribution Plant	Line 17 - Line 29	$ 53,839,512	$ 56,542,045	$ 55,190,779			$ -
39	Net General Plant	Line 19 - Line 30	$ 159,051,704	$ 147,638,553	$ 153,345,129			$ 48,888,146
40	Net Completed Construction Not Classified	Line 20	$ 274,138,335	$ 292,683,250	$ 283,410,793			$ 94,876,195
41	108.8 Retirement Work in Progress	Line 31	$ 1,067,648	$ 1,978,451	$ 1,523,050			$ (1,288,839)
42	Total Net Plant in Service	Sum	$ 2,384,541,248	$ 2,426,239,127	$ 2,405,390,188			$ 697,631,950
43	Adjustments to Rate Base							
44	105 Electric Plant Held For Future Use - Production	Worksheet N Line 1, Cols E, H, and K	$ 74,369,029	$ 74,369,029	$ 74,369,029	Direct Zero	0.000%	$ -
45	105 Electric Plant Held For Future Use - Transmission	Worksheet N Line 16, Cols E, H, and K	$ 2,842,188	$ 2,582,639	$ 2,712,413	Direct		$ 2,712,413
46	105 Electric Plant Held For Future Use - Distribution	Worksheet N Line 17, Cols E, H, and K	$ -	$ -	$ -	Direct Zero	0.000%	$ -
47	105 Electric Plant Held for Future Use - General	Worksheet N Line 18, Cols E, H, and K	$ -	$ -	$ -	T-Wage Allocation	31.881%	$ -
48	105 Electric Plant Held for Future Use - Intangible	Worksheet N Line 19, Cols E, H, and K	$ -	$ -	$ -	T-Wage Allocation	31.881%	$ -
49	107 Construction Work in Progress	Worksheet F Line 98, Col D thru F and Worksheet R Line 1 Col K	$ 172,228,792	$ 185,623,445	$ 178,926,119	Direct		$ 35,117,570
50	Working Capital							
51	Total Transmission O&M Costs	Worksheet B, Line 29, Col F and I			$ 193,647,480			$ 79,857,585
52	Billing Lag in Days	Worksheet F, Line 1 Col F			45			45
53	Working Capital	Line 51 * Line 52 / 365			$ 23,874,347			$ 9,845,456
54	Prepayments	Worksheet F, Line 61, Col D thru F	$ 15,506,647	$ 15,958,666	$ 15,732,657	T-Plant Allocation	26.672%	$ 4,196,177
55	M&S Coal	Worksheet F, Line 113 Col D thru F	$ 34,732,719	$ 32,081,531	$ 33,407,125	Direct Zero	0.000%	$ -
56	M&S Other Fuel	Worksheet F, Line 114 Col D thru F	$ 7,253,526	$ 5,731,151	$ 6,492,339	Direct Zero	0.000%	$ -
57	M&S Production Plant Parts	Worksheet F, Line 115 Col D thru F	$ 43,031,438	$ 44,736,952	$ 43,884,195	Direct Zero	0.000%	$ -
58	M&S Station Transformers & Equipment	Worksheet F, Line 116 Col D thru F	$ 17,898,161	$ 19,884,963	$ 18,891,562	T-Tran Stations	59.989%	$ 11,332,771
59	M&S Line Materials & Supplies	Worksheet F, Line 117 Col D thru F	$ 5,442,887	$ 6,047,079	$ 5,744,983	T-Tran Lines	84.271%	$ 4,841,377
60	M&S Other	Worksheet F, Line 118 Col D thru F	$ (2,001,323)	$ -	$ (1,000,662)	T-Plant Allocation	26.672%	$ (266,894)
61	Materials and Supplies	Sum	$ 106,357,406	$ 108,481,676	$ 107,419,541			$ 15,907,254
62	Network Upgrades Credit	Worksheet H, Line 1, Col G	$ (781,287)	$ (273,161)	$ (527,224)	Direct		$ (527,224)
63	Total Working Capital and Adjustments				$ 403,034,105			$ 67,778,870
64	Rate Base	Total			$ 2,808,424,293			$ 764,883,596

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
O&M, Depreciation, and Return Expenses
Data: Year Ending December 31, 2018

A Line	B Description	C Reference	D Total Company	E Total Company	F Total Company	G Allocation Factor	H Allocation %	I Transmission ATRR West
1	Transmission Operation & Maintenance Expenses		Lines	Stations				
2	560 Supervision and Engineering	Worksheet G, Line 1 Cols D Thru F	$ 7,483,551	$ 13,898,024	$ 21,381,575	T-Tran Plant	72.624%	$ 15,528,215
3	561 Load Dispatching	Worksheet G, Line 2 Cols D and F	$ 9,445,684	$ -	$ 9,445,684	Direct Zero	0.000%	$ -
4	562 Station Expenses	Worksheet G, Line 3 Cols E Thru F	$ -	$ 17,184,925	$ 17,184,925	T-Tran Stations	59.989%	$ 10,308,984
5	563 Overhead Line Expenses	Worksheet G, Line 4 Cols D and F	$ 7,402,243	$ -	$ 7,402,243	T-Tran Lines	84.271%	$ 6,237,973
6	564 Underground Line Expenses	Worksheet G, Line 5 Cols D and F	$ -	$ -	$ -	T-Tran Lines	84.271%	$ -
7	565 Transmission of Electricity by others	Worksheet G, Line 8 Cols D and F and Worksheet O, Line 7, Col F	$ 51,771,390	$ -	$ 51,771,390	Direct Zero	0.000%	$ -
8	566 Miscellaneous Expenses	Worksheet G, Line 6 Cols D Thru F	$ 7,407,103	$ 13,756,049	$ 21,163,152	T-Tran Plant	72.624%	$ 15,369,587
9	567 Rents	Worksheet G, Line 9 Cols D Thru F	$ 513,011	$ 952,734	$ 1,465,745	T-Tran Stations	59.989%	$ 879,279
10	568 Supervision and Engineering	Worksheet G, Line 11 Cols D Thru F	$ 4,797,786	$ 8,910,175	$ 13,707,961	T-Tran Plant	72.624%	$ 9,955,308
11	569 Structures	Worksheet G, Line 12 Cols E Thru F		$ -	$ -	T-Tran Stations	59.989%	$ -
12	570 Station Equipment	Worksheet G, Line 13 Cols E Thru F		$ 6,628,274	$ 6,628,274	T-Tran Stations	59.989%	$ 3,976,204
13	571 Overhead Lines	Worksheet G, Line 14 Cols D and F	$ 5,515,564		$ 5,515,564	T-Tran Lines	84.271%	$ 4,648,042
14	572 Underground Lines	Worksheet G, Line 15 Cols D and F	$ -		$ -	T-Tran Lines	84.271%	$ -
15	573 Miscellaneous Transmission Plant	Worksheet G, Line 16 Cols D Thru F	$ 1,727,119	$ 3,207,508	$ 4,934,627	T-Tran Plant	72.624%	$ 3,583,737
16	575.1-575.8 RTO/ISO Expense - Operation	Worksheet P, Line 2, Col F	$ -		$ -	Direct 100	100.000%	$ -
17	576.1-576.5 RTO/ISO Expense - Maintenance	Worksheet P, Line 4, Col F	$ -		$ -	Direct 100	100.000%	$ -
18	Transmission O&M	Subtotal	$ 96,063,451	$ 64,537,689	$ 160,601,140			$ 70,487,331
19	Customer Accounting	Worksheet F, Line 27 Col F			$ 756,212	T-Wage Allocation	31.881%	$ 241,089
20	Customer Services & Information	Worksheet F, Line 28 Col F			$ 3,491,203	Direct Zero	0.000%	$ -
21	Sales	Worksheet F, Line 29 Col F			$ -	Direct Zero	0.000%	$ -
22	Customer Related Expense	Subtotal			$ 4,247,415			$ 241,089
23	Administrative & General Expense							
24	Admin and General Expense	Worksheet F, Line 30 Col F Less Line 25 and Line 26			$ 15,522,080	T-Wage Allocation	31.881%	$ 4,948,613
25	Account 928 Expenses - West	Worksheet S, Line 4, Col F			$ 57,964	Direct 100	100.000%	$ 57,964
26	Account 928 Expenses - East	Worksheet S, Line 4, Col E			$ 287,755	Direct Zero	0.000%	$ -
27	Maintenance Expense General Plant	Worksheet F, Line 37 Col F			$ 12,931,126	T-Wage Allocation	31.881%	$ 4,122,588
28	Total A&G Expenses	Subtotal			$ 28,798,925			$ 9,129,165
29	Subtotal O&M				$ 193,647,480			$ 79,857,585
			Total Company	Adjustment	Adjusted Total			
30	Depreciation Expense							
31	Depreciation Expense-Trans	Worksheet L, Line 11 Col H				Direct		$ 13,835,645
32	Depreciation Expense-General	Worksheet L, Line 42 Col J				Direct		$ 7,570,828
33	Amort of Intangible Plant	Worksheet L, Line 45 Col J				Direct		$ 1,262,216
34	Total Depreciation & Amortization	Subtotal						$ 22,668,688
35	Taxes	Worksheet F, Line 41 Col F	$ (497,857)			T-Net Allocation	29.003%	$ (144,393)
36	Return	Worksheet C, Line 7, Col K						$ 46,628,295
37	Network Upgrades Interest Expense					Direct		$ 14,978
38	Revenue Requirement before revenue credits							$ 149,025,153

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Return
Data: Year Ending December 31, 2018

A	B	C	D	E	F	G	H	I	J	K
Line	**Description**	**Reference**	**Total Company EOY**	**Actual Cap Structure Weight (Note A)**	**Low Hypothetical Equity (Note A)**	**High Hypothetical Equity (Note A)**	**Applied Cap Structure (Note B)**	**Interest Expense**	**Cost of Capital (Note C)**	**Weighted Rate of Return (Note D)**
1	Return Based on Defined ROE									
2	Total Long Term Debt	Worksheet F, Lines 66 and 69, Col F and Line 42, Col F	$ 2,818,775,443	69.78%	64.76%	31.14%	59.71%	$ 126,485,885	4.49%	2.68%
3	Notes Payable (Note E)	Worksheet F, Line 68, Col F; Worksheet F Line 44 Col F if balance is >0	$ 204,145,188	5.05%	0.00%	0.00%	5.05%	$ 5,640,594	2.76%	0.14%
4	Total Margins and Equities	Worksheet F, Line 65, Col F	$ 1,016,374,704	25.16%	35.24%	68.86%	35.24%	N/A	9.30%	3.28%
5	Total Capitalization	Subtotal	$ 4,039,295,335	100.00%	100.00%	100.00%	100.00%	$ 132,126,479		6.10%
6	Rate Base	Worksheet A, Line 64, Col I								$ 764,883,596
7	Return on Rate Base	Line 5 * Line 6								$ 46,628,295

8 Notes:
9 A.) The capital structure listed in Column (E) is calculated based on total capitalization amounts listed in Column (D). The capital structures listed in Columns (F) and (G) are fixed and cannot be modified or deleted absent authorization from FERC via a Section 205 or 206 filing.
10 B.) In the case where Tri-State's actual capital structure (Column (E)) contains a Total Margins and Equities percentage between 35.24 percent and 68.86 percent, Column (H) should be populated with the actual capital structure. In the case where Tri-State's actual Margins and Equities percentage is below 35.24 percent, Column (H) should be populated with the the capital structure listed in Column (F). In the case where Tri-State's actual Margins and Equities percentage is above 68.86 percent, Column (H) should be populated with the capital structure listed in Column (G).
11 C.) The Cost of Capital for Total Margins and Equities (ROE) is fixed and cannot be modified or deleted absent authorization from FERC via a Section 205 or 206 filing. The Cost of Capital for Long Term Debt and Notes Payable is calculated by dividing the interest expense in Column (I) by the total amount in Column (D).
12 D.) Column (K) values for lines 2-4 equal Column (H) values multiplied by Column (J) values.
13 E.) Only populate if the balance is greater than zero.
14 F.) RUSFOR, Part A, Sect A, L24b for long term debt and RUSFOR, Part A, Sect A, L26b for notes payable.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Load
Data: Year Ending December 31, 2018

A	B	C	D	E
Line	Description	Total CP Load	Adjustments	Network Demand (KW) - West
1	January	2,149,744		2,149,744
2	February	2,145,012		2,145,012
3	March	2,053,356		2,053,356
4	April	1,689,571		1,689,571
5	May	2,099,731		2,099,731
6	June	2,575,123		2,575,123
7	July	2,619,396		2,619,396
8	August	2,466,376		2,466,376
9	September	2,243,822		2,243,822
10	October	1,954,419		1,954,419
11	November	2,168,971		2,168,971
12	December	2,315,519		2,315,519
13	Total (kW-Mo)	26,481,040	-	26,481,040
14	Average (kW-Mo)	2,206,753	-	2,206,753

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Allocation Factors
Data: Year Ending December 31, 2018

A Line	B Description	C Reference	D Total	E Allocation Factor	F Allocation	G Allocated
1	Production Wages & Salaries	Worksheet K, Line 2, Col F	54,502,293	Direct Zero	0.000%	$ -
2	Transmission Wages & Salaries	Worksheet K, Line 3, Col F Less Line 14, Col F	47,700,409	T-Tran Plant	72.624%	$ 34,642,080
3	561 Load Dispatch Salaries	Worksheet K, Line 14, Col F	6,494,098	Direct Zero	0.000%	$ -
4	Distribution Wages & Salaries	Worksheet K, Line 4, Col F	465,699	Direct Zero	0.000%	$ -
5	Customer Accounting	Worksheet K, Line 5, Col F	405,878	T-Tran Plant	72.624%	$ 294,766
6	Customer Service	Worksheet K, Line 6, Col F	16,371	Direct Zero	0.000%	$ -
7	Customer Sales	Worksheet K, Line 7, Col F	-	Direct Zero	0.000%	$ -
8		Sum	$ 109,584,747			$ 34,936,846
9	**T-Wage Allocation**					**31.88%**
10	352-353 Transmission Stations	Worksheet F, Sum (Lines 79 and 80), Col F and Worksheet U, Line 10, (Cols I and K)/2	$ 603,264,475			$ 361,889,505
11	**T-Tran Stations**					**59.99%**
12	Transmission Lines	Worksheet F, Sum (Lines 78 and 81), Col F and Worksheet V, Line 10, (Cols I and K)/2	$ 654,471,465			$ 551,532,195
13	**T-Tran Lines**					**84.27%**
14	Transmission Qualifying Plant	Lines 10 and 12 above and Worksheet A, Line 12, Col I	$ 1,257,735,940			$ 913,421,700
15	**T-Tran Plant**					**72.62%**
16	Plant in Service	Worksheet A, Line 21, Col F and I	$ 4,508,475,315			$ 1,202,489,909
17	**T-Plant Allocation**					**26.67%**
18	Net Plant in Service	Worksheet A, Line 42, Col F and I	$ 2,405,390,188			$ 697,631,950
19	**T-Net Allocation**					**29.00%**
20	**Direct Zero**					**0.00%**
21	**Direct 100**					**100.00%**

Tri-State Generation and Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE
Inputs
Data: Year Ending December 31, 2018

A Line	B Description	C Reference	D BOY	E EOY	F Total
1	Billing Lag in days	Industry Standard			45
2	**Monthly Load (Total KW)**				
3	Jan	Company Records			2,149,744
4	Feb	Company Records			2,145,012
5	Mar	Company Records			2,053,356
6	Apr	Company Records			1,689,571
7	May	Company Records			2,099,731
8	Jun	Company Records			2,575,123
9	Jul	Company Records			2,619,396
10	Aug	Company Records			2,466,376
11	Sep	Company Records			2,243,822
12	Oct	Company Records			1,954,419
13	Nov	Company Records			2,168,971
14	Dec	Company Records			2,315,519
15	**RUSFOR Input**				
16	Electric Energy Revenues	RUSFOR, Part A, Section A, Line 1, Col. b			$ 1,322,313,285
17	Income From Leased Property	RUSFOR, Part A, Section A, Line 2, Col. b			$ -
18	Other Operating Revenue & Income	RUSFOR, Part A, Section A, Line 3, Col. b			$ (22,519,040)
19	Total Operating Revenues & Patronage Capital	Subtotal			$ 1,299,794,245
20	**Operating Expense**				
21	Op Exp.-Production excluding fuel	RUSFOR, Part A, Section A, Line 5, Col. b			$ 173,085,065
22	Op Exp.-Production fuel	RUSFOR, Part A, Section A, Line 6, Col. b			$ 233,871,240
23	Op Exp.-Other Power Supply	RUSFOR, Part A, Section A, Line 7, Col. b			$ 343,509,369
24	Op Exp.-Transmission	RUSFOR, Part A, Section A, Line 8, Col. b			$ 129,814,713
25	Op Exp.-RTO/ISO	RUSFOR, Part A, Section A, Line 9, Col. b			$ -
26	Op Exp.-Distribution	RUSFOR, Part A, Section A, Line 10, Col. b			$ 927,992
27	Op Exp.-Consumer Accounts	RUSFOR, Part A, Section A, Line 11, Col. b			$ 756,212
28	Op Exp.-Customer Service	RUSFOR, Part A, Section A, Line 12, Col. b			$ 3,491,203
29	Op Exp.-Sales	RUSFOR, Part A, Section A, Line 13, Col. b			$ -
30	Op Exp.-Admin and General	RUSFOR, Part A, Section A, Line 14, Col. b			$ 15,867,799
31	Total Operation Expense	Subtotal			$ 901,323,593

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Inputs
Data: Year Ending December 31, 2018

A Line	B Description	C Reference	D BOY	E EOY	F Total
32	**Maintenance Expense**				
33	Maint. Exp.-Production	RUSFOR, Part A, Section A, Line 16, Col. b			$ 93,781,678
34	Maint. Exp.-Transmission	RUSFOR, Part A, Section A, Line 17, Col. b			$ 30,786,426
35	Maint. Exp.-RTO/ISO	RUSFOR, Part A, Section A, Line 18, Col. b			$ -
36	Maint. Exp.-Distribution	RUSFOR, Part A, Section A, Line 19, Col. b			$ 122,745
37	Maint. Exp.-General Plant	RUSFOR, Part A, Section A, Line 20, Col. b			$ 12,931,126
38	Total Maintenance Expense	Subtotal			$ 137,621,975
39	**Interest, Taxes and Other Deductions**				
40	Depreciation & Amortization Expense	RUSFOR, Part A, Section A, Line 22, Col. b			$ 122,702,198
41	Taxes	RUSFOR, Part A, Section A, Line 23, Col. b			$ (497,857)
42	Interest on Long Term Debt	RUSFOR, Part A, Section A, Line 24, Col. b			$ 126,485,885
43	Interest Charged to Construction - Credit	RUSFOR, Part A, Section A, Line 25, Col. b			$ (8,220,608)
44	Other Interest Expense	RUSFOR, Part A, Section A, Line 26, Col. b			$ 5,640,594
45	Asset Retirement Obligations	RUSFOR, Part A, Section A, Line 27, Col. b			$ 61,189
46	Other Deductions	RUSFOR, Part A, Section A, Line 28, Col. b			$ 8,378,319
47	Total Cost of Electric Service	Subtotal			$ 1,293,495,288
48	Operating Margins	Calculated			$ 6,298,957
49	Interest Income	RUSFOR, Part A, Section A, Line 31, Col. b			$ 5,272,014
50	Allowance For Funds Used During Construction	RUSFOR, Part A, Section A, Line 32, Col. b			$ -
51	Income (Loss) from Equity Investments	RUSFOR, Part A, Section A, Line 33, Col. b			$ (2,055,335)
52	Other Non-operating Income (Net)	RUSFOR, Part A, Section A, Line 34, Col. b			$ 5,889,378
53	Generations & Transmission Capital Credits	RUSFOR, Part A, Section A, Line 35, Col. b			$ 21,353,592
54	Other Capital Credits and Patronage Dividends	RUSFOR, Part A, Section A, Line 36, Col. b			$ 5,974,607
55	Extraordinary Items	RUSFOR, Part A, Section A, Line 37, Col. b			$ -
56	**Net Patronage Capital or Margins**	Calculated			$ 42,733,213
57	**Section B. Balance Sheet**				
58	**Assets**		BOY	EOY	Average
59	Construction Work in Progress	RUSFOR, Part A, Section B, Line 2	$ 172,228,793	$ 189,268,656	$ 180,748,725
60	Notes Receivable (Net)	RUSFOR, Part A, Section B, Line 19	$ 218,150	$ 218,150	$ 218,150
61	Prepayments *(Acct 165)*	Past Year & Current RUSFOR, Part A, Section B, Line 25	$ 15,506,647	$ 15,958,666	$ 15,732,657
62	Other Current and Accrued Assets	Past Year & Current RUSFOR, Part A, Section B, Line 26	$ 11,038,308	$ 13,535,309	$ 12,286,809
63	Accumulated Deferred Income Taxes *(Acct 190)*	Past Year & Current RUSFOR, Part A, Section B, Line 31	$ 153,706,335	$ 158,922,062	$ 156,314,199

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Inputs
Data: Year Ending December 31, 2018

A Line	B Description	C Reference	D BOY	E EOY	F Total
64	**Liabilities**				Total
65	Total Margins & Equities	RUSFOR, Part A, Section B, Line 39		$ 1,016,374,704	$ 1,016,374,704
66	Total Long Term Debt	RUSFOR, Part A, Section B, Line 43		$ 2,818,775,443	$ 2,818,775,443
67	Obligations Under Capital Leases - Non Current	RUSFOR, Part A, Section B, Line 44		$ -	$ -
68	Notes Payable	RUSFOR, Part A, Section B, Line 47		$ 204,145,188	$ 204,145,188
69	Current Maturities Long Term Debt	RUSFOR, Part A, Section B, Line 49		$ -	$ -
70	Current Maturities Long Term Debt - Rural Dev.	RUSFOR, Part A, Section B, Line 50		$ -	$ -
71	Accumulated Deferred Income Taxes *(Acct 283)*	RUSFOR, Part A, Section B, Line 57		$ 188,278,258	$ 188,278,258
			BOY	EOY	Average
72	301-303 Total Intangible Plant	Past Year & Current RUSFOR, Part H, Sect A, Line 1	$ 143,815,271	$ 144,127,021	$ 143,971,146
73	310 Steam Plant	Past Year & Current RUSFOR, Part H, Section A, Line 2	$ 1,957,298,716	$ 2,001,741,701	$ 1,979,520,209
74	320 Nuclear Plant	Past Year & Current RUSFOR, Part H, Section A, Line 3	$ -	$ -	$ -
75	330 Hydro Plant	Past Year & Current RUSFOR, Part H, Section A, Line 4	$ -	$ -	$ -
76	340 Other Prod Plant	Past Year & Current RUSFOR, Part H, Section A, Line 5	$ 283,327,691	$ 284,231,267	$ 283,779,479
77	**Total Production Plant**	Subtotal	$ 2,240,626,407	$ 2,285,972,968	2,263,299,688
78	350 Land & Land Rights	Past Year & Current RUSFOR, Part H, Section A, Line 7	$ 127,713,237	$ 131,239,316	$ 129,476,277
79	352 Structures and Improvements	Past Year & Current RUSFOR, Part H, Section A, Line 8	$ 46,184,559	$ 54,560,378	$ 50,372,469
80	353 Station Equipment	Past Year & Current RUSFOR, Part H, Section A, Line 9	$ 535,910,825	$ 569,873,188	$ 552,892,007
81	354 thru 359.1 Other Transmission Plant	Past Year & Current RUSFOR, Part H, Section A, Line 10	$ 524,894,264	$ 525,096,113	$ 524,995,189
82	**Total Transmission Plant**	Subtotal	$ 1,234,702,885	$ 1,280,768,995	1,257,735,940
83	360 Land and Land Rights	Past Year & Current RUSFOR, Part H, Section A, Line 12	$ 1,553,591	$ 1,553,591	$ 1,553,591
84	361 Structures and Improvements	Past Year & Current RUSFOR, Part H, Section A, Line 13	$ 9,573,419	$ 9,830,550	$ 9,701,985
85	362 Station Equipment	Past Year & Current RUSFOR, Part H, Section A, Line 14	$ 82,788,360	$ 84,532,517	$ 83,660,439
86	363-374 Other Distribution Plant	Past Year & Current RUSFOR, Part H, Section A, Line 15	$ -	$ -	$ -
87	**Total Distribution Plant**	Subtotal	$ 93,915,370	$ 95,916,658	$ 94,916,014
88	380-386 RTO/ISO Plant	Past Year & Current RUSFOR, Part H, Section A, Line 17	$ -	$ -	$ -
89	389 thru 399.1 Total General Plant	Past Year & Current RUSFOR, Part H, Section A, Line 18	$ 466,525,796	$ 463,757,674	$ 465,141,735
90	**Electric Plant In Service**	Subtotal	$ 4,179,585,729	$ 4,270,543,316	4,225,064,523
91	102 Electric Plant Purchased or Sold	Past Year & Current RUSFOR, Part H, Section A, Line 20	$ -	$ -	$ -
92	104 Electric Plant Leased to Others	Past Year & Current RUSFOR, Part H, Section A, Line 21	$ -	$ -	$ -
93	105 Electric Plant Held For Future Use	Past Year & Current RUSFOR, Part H, Section A, Line 22	$ 77,211,216	$ 76,951,667	$ 77,081,442
94	106 Completed Construction Not Classified	Past Year & Current RUSFOR, Part H, Section A, Line 23	$ 274,138,335	$ 292,683,250	$ 283,410,793
95	114 Acquisition Adjustment	Past Year & Current RUSFOR, Part H, Section A, Line 24	$ 43,064,740	$ 26,286,690	$ 34,675,715
96	118 Other Utility Plant	Past Year & Current RUSFOR, Part H, Section A, Line 25	$ -	$ -	$ -
97	120 Nuclear Fuel Assemblies	Past Year & Current RUSFOR, Part H, Section A, Line 26	$ -	$ -	$ -
98	107 Construction Work in Progress	Past Year & Current RUSFOR, Part H, Section A, Line 28	$ 172,228,792	$ 185,623,445	$ 178,926,119
99	**Total Utility Plant**	Subtotal	$ 4,746,228,812	$ 4,852,088,368	4,799,158,590
100	Depreciation and Amortization Reserves		BOY	EOY	Average
101	108.1 Depr Rsv. of Steam Plant	Past Year & Current RUSFOR, Part H, Section B, Line 1	$ 1,023,235,337	$ 1,060,707,871	$ 1,041,971,604
102	108.2 Depr Rsv. of Nuclear Plant	Past Year & Current RUSFOR, Part H, Section B, Line 2	$ -	$ -	$ -
103	108.3 Depr Rsv. of Hydraulic Plant	Past Year & Current RUSFOR, Part H, Section B, Line 3	$ -	$ -	$ -
104	108.4 Depr Rsv. of Other Prod Plant	Past Year & Current RUSFOR, Part H, Section B, Line 4	$ 113,924,205	$ 116,120,844	$ 115,022,525
105	108.5 Depreciation of Transmission Plant	Past Year & Current RUSFOR, Part H, Section B, Line 5	$ 506,575,074	$ 524,819,021	$ 515,697,048

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Inputs

Data: Year Ending December 31, 2018

A Line	B Description	C Reference	D BOY	E EOY	F Total
106	108.6 Depreciation of Distribution Plant	Past Year & Current RUSFOR, Part H, Section B, Line 6	$ 40,075,858	$ 39,374,613	$ 39,725,236
107	108.7 Depreciation of General Plant	Past Year & Current RUSFOR, Part H, Section B, Line 7	$ 307,474,092	$ 316,119,121	$ 311,796,607
108	108.8 Retirement Work in Progress	Past Year & Current RUSFOR, Part H, Section B, Line 8	$ (1,067,648)	$ (1,978,451)	$ (1,523,050)
109	111 Amort. of Electric Plant in Service	Past Year & Current RUSFOR, Part H, Section B, Line 12	$ 78,965,898	$ 81,824,420	$ 80,395,159
110	115 Amort. of Acquisition Adj.	Past Year & Current RUSFOR, Part H, Section B, Line 15	$ 33,293,799	$ 34,300,379	$ 33,797,089
111	**Total Depr Reserves for Electric Plant**	Subtotal	$ 2,102,476,615	$ 2,171,287,818	2,136,882,217
112	<u>Materials and Supplies</u>		BOY	EOY	<u>Average</u>
113	M&S Coal	Past Year & Current RUSFOR, Part H, Section G, Line 1	$ 34,732,719	$ 32,081,531	$ 33,407,125
114	M&S Other Fuel	Past Year & Current RUSFOR, Part H, Section G, Line 2	$ 7,253,526	$ 5,731,151	$ 6,492,339
115	M&S Production Plant Parts	Past Year & Current RUSFOR, Part H, Section G, Line 3	$ 43,031,438	$ 44,736,952	$ 43,884,195
116	M&S Station Transformers & Equipment	Past Year & Current RUSFOR, Part H, Section G, Line 4	$ 17,898,161	$ 19,884,963	$ 18,891,562
117	M&S Line Materials & Supplies	Past Year & Current RUSFOR, Part H, Section G, Line 5	$ 5,442,887	$ 6,047,079	$ 5,744,983
118	M&S Other	Past Year & Current RUSFOR, Part H, Section G, Line 6	$ (2,001,323)	$ -	$ (1,000,662)
119	Materials and Supplies	Subtotal	$ 106,357,406	$ 108,481,676	107,419,541
120	<u>Depreciation Expense</u>				<u>Total</u>
121	40360 Depreciation Expense - General Plant	Trial Balance			$ 24,909,164
122	40361 Depreciation Expense - EMS Equipment (Depreciation Accounts for 390 391 393 - 399)	Trial Balance			$ -
123	40369 Depreciation Expense - General Plant Southern	Trial Balance			$ -
124	40370 Depreciation Expense - Sedans, Compact Utility Vehicles, Compact Pick-ups	Trial Balance			$ -
125	40371 Depreciation Expense - Vans and Wagons	Trial Balance			$ -
126	40372 Depreciation Expense - Full-Size Pickups, Vans, Utility Vehicles	Trial Balance			$ -
127	40373 Depreciation Expense - Bucket Trucks, Diggers	Trial Balance			$ -
128	40374 Depreciation Expense - Company Aircraft	Trial Balance			$ -
129	40375 Depreciation Expense - Small Heavy Trucks	Trial Balance			$ -
130	40376 Depreciation Expense - Medium Trucks, Flatbeds, Knuckle Booms, Etc.	Trial Balance			$ -
131	40377 Depreciation Expense - Snowcats	Trial Balance			$ -
132	40378 Depreciation Expense - Equipment (Dozers, Backhoes, etc.)	Trial Balance			$ -
133	40388 Depreciation Expense - AROs	Trial Balance			$ 1,315,482
134	40398 Depreciation Expense - AROs	Trial Balance			$ -
135	General Plant Depreciation Expense	Subtotal			$ 26,224,645
136	40400 Amortization - Franchises and Consents (Amortization Account for 302)	Trial Balance			$ -
137	40409 Amortization of Lmtd Term Electric Plant Southern Franchises	Trial Balance			$ -
138	40500 Amortization of Other Electric Plant (Amortization Account for Deferred Debit Accounts)	Trial Balance			$ 340,422
139	40509 Amortization of Other Electric Plant Southern	Trial Balance			$ -
140	40510 Amortization Miscellaneous Intangible Generation	Trial Balance			$ -
141	40530 Amortization-Miscellaneous Intangible Lines	Trial Balance			$ 1,268,998
142	40540 Amortization-Miscellaneous Intangible Substations	Trial Balance			$ 1,167,162
143	40600 Amortization of Electric Plant Acquisition Adjustments (Amortization Account for 114 301)	Trial Balance			$ 1,006,581
144	40609 Amortization of Electric Plant Acquisition Adjust. Southern	Trial Balance			$ -
145	40700 Amortization of Property Losses Rollup	Trial Balance			$ -
146	Amortization of Property	Subtotal			$ 3,783,162

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Inputs

Data: Year Ending December 31, 2018

A Line	B Description	C Reference	D BOY	E EOY	F Total
	General and Intangible Plant Inputs		BOY	EOY	Average
147	390 - Structures and Improvements	Trial Balance	$ 70,780,714	$ 70,763,097	$ 70,771,905
148	391.1 - Personal Computers	Company Records	$ 41,782,450	$ 45,283,293	$ 43,532,871
149	391.11 - Furniture	Company Records	$ 5,629,357	$ 5,604,790	$ 5,617,073
150	391.12 - Office Equipment	Company Records	$ 2,517,136	$ 2,517,136	$ 2,517,136
151	391.13 - Computer Hardware	Company Records	$ 9,390,224	$ 9,390,224	$ 9,390,224
152	391.14 - LRS Office Equipment	Company Records	$ 129,222	$ 143,901	$ 136,562
153	391.15 - EMS Office Equipment	Company Records	$ 24,836	$ 24,836	$ 24,836
154	391.16 - EMS Computer Equipment	Company Records	$ 4,983,177	$ 4,983,177	$ 4,983,177
155	391.17 - CO41 OWNED AT JMS	Company Records	$ 131,402	$ 131,402	$ 131,402
156	391.18 - SOFTWARE	Company Records	$ 60,524,876	$ 60,424,469	$ 60,474,673
157	391.19 - Plains Furniture and Equipment	Company Records	$ 10,832,216	$ 2,228,027	$ 6,530,121
158	392.1 - Transportation Equipment	Company Records	$ 387,292	$ 379,792	$ 383,542
159	392.11 - Airplane	Company Records	$ 5,275,410	$ 5,275,410	$ 5,275,410
160	392.12 - Snow Cats/Trailers	Company Records	$ 2,714,286	$ 2,654,345	$ 2,684,315
161	392.13 - LRSVehicles	Company Records	$ 1,159,752	$ 1,253,543	$ 1,206,648
162	392.14 - Plains Transportation Equipment	Company Records	$ 3,036,648	$ 3,036,648	$ 3,036,648
163	392.15 - Diesel Trucks	Company Records	$ 1,496,988	$ 1,256,708	$ 1,376,848
164	392.16 - Craig- Fuel Vehicles	Company Records	$ 46,097	$ 46,097	$ 46,097
165	392.17 - Craig- Maintenance Vehicles	Company Records	$ 173,103	$ 173,103	$ 173,103
166	392.18 - Craig- Operating Vehicles	Company Records	$ 326,429	$ 326,429	$ 326,429
167	392.19 - Pickups	Company Records	$ 18,402,546	$ 20,410,026	$ 19,406,286
168	392.2 - Autos	Company Records	$ 2,315,404	$ 2,140,603	$ 2,228,004
169	392.21 - Heavy Duty Trucks	Company Records	$ 7,006,351	$ 6,346,163	$ 6,676,257
170	393 - Stores Equipment	Trial Balance	$ 1,434,139	$ 1,474,025	$ 1,454,082
171	394 - Tools, Shop and Garage Equipment	Trial Balance	$ 10,038,158	$ 10,190,694	$ 10,114,426
172	395 - Lab & Testing Equipment	Trial Balance	$ 14,566,845	$ 14,701,803	$ 14,634,324
173	396 - Power Operated Equipment	Trial Balance	$ 31,528,080	$ 33,134,561	$ 32,331,320
174	397 - Communications Equipment	Trial Balance	$ 152,444,837	$ 152,047,089	$ 152,245,963
175	398 - Miscellaneous	Trial Balance	$ 2,487,410	$ 2,486,304	$ 2,486,857
176	303 - Miscellaneous Intangible	Trial Balance	$ 143,812,569	$ 144,124,319	$ 143,968,444

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

O&M

Data: Year Ending December 31, 2018

A	B	C	D	E	F
	Expenses and Costs				
Line	**Item**	**Account Name**	**Lines (a)**	**Stations (b)**	**Total**
	Transmissions Operations				
1	Supervision and Engineering	560	$ 7,483,551	$ 13,898,024	$ 21,381,575
2	Load Dispatching	561	$ 9,445,684		$ 9,445,684
3	Station Expenses	562		$ 17,184,925	$ 17,184,925
4	Overhead Line Expenses	563	$ 7,402,243		$ 7,402,243
5	Underground Line Expenses	564	$ -		$ -
6	Miscellaneous Expenses	566	$ 7,407,103	$ 13,756,049	$ 21,163,152
7	**Subtotal (1 thru 6)**		**$ 31,738,581**	**$ 44,838,998**	$ 76,577,579
8	Transmission of Electricity by others	565	$ 51,771,390		$ 51,771,390
9	Rents	567	$ 513,011	$ 952,734	$ 1,465,745
10	**Total Transmission Operations (7 thru 9)**		**$ 84,022,982**	**$ 45,791,732**	$ 129,814,714
	Transmission Maintenance				
11	Supervision and Engineering	568	$ 4,797,786	$ 8,910,175	$ 13,707,961
12	Structures	569		$ -	0
13	Station Equipment	570		$ 6,628,274	$ 6,628,274
14	Overhead Lines	571	$ 5,515,564		$ 5,515,564
15	Underground Lines	572			0
16	Miscellaneous Transmission Plant	573	$ 1,727,119	$ 3,207,508	$ 4,934,627
17	**Total Transmission Maintenance (11 thru 16)**		**$ 12,040,469**	**$ 18,745,957**	$ 30,786,426
18	**Total Transmission Expense (10+17)**		**$ 96,063,451**	**$ 64,537,689**	$ 160,601,140
19	RTO/ISO Expense - Operation	575.1-575.8	$ -	$ -	$ -
20	RTO/ISO Expense - Maintenance	576.1-576.5	$ -	$ -	$ -
21	**Total RTO/ISO Expense (19+20)**		**$ -**	**$ -**	$ -
22	Distribution Expense - Operation	580-589		$ 927,992	$ 927,992
23	Distribution Expense - Maintenance	590-598		$ 122,745	$ 122,745
24	**Total Distribution Expense (22+23)**		**-**	**$ 1,050,737**	$ 1,050,737
25	**Total Operation and Maintenance (18+21+24)**		**$ 96,063,451**	**$ 65,588,426**	$ 161,651,877
	Fixed Costs				
26	Depreciation - Transmission	403.5	$ 10,893,490	$ 14,887,844	$ 25,781,334
27	Depreciation - Distribution	403.6		$ 1,466,437	$ 1,466,437
28	Interest - Transmission	427.0	$ -	$ -	$ -
29	Interest - Distribution	427.0		$ -	$ -
30	**Total Transmission (18+26+28)**		**$ 106,956,941**	**$ 79,425,533**	$ 186,382,474
31	**Total Distribution (24+27+29)**		**-**	**$ 2,517,174**	$ 2,517,174
32	**Total Lines and Stations (21+30+31)**		**$ 106,956,941**	**$ 81,942,707**	$ 188,899,648

33 Notes:

34 A.) Source: RUSFOR, Part I.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Network Credits

Data: Year Ending December 31, 2018

A Line	B Account (A)	C Account Description	D BOY
1	252	Network Upgrades Credit	$ (781,287)
2	252	Network Upgrades Interest Expense	
3			
4		Total Account 252	$ (781,287)

5 Notes:

6 A.) Source: Trial Balance.

7 B.) The addition of new lines and the removal of outdated lines necessary to populate or rem
future years does not require a Federal Power Act section 205 or 206 filing. The addition or r
those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Page 11
Worksheet H

E EOY	F Average	G West
$ (273,161)	$ (527,224)	$ (527,224)
		$ 14,978
$ (273,161)	$ (527,224)	(512,246)

ıove data in the work paper with the changes in
ɾemoval of columns and formulas contained with

Tri-State Generation & Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Depreciation Rates
Data: Year Ending December 31, 2018

A Line	B Account No.	C Description	D Depreciation/Amortization Rate
1		**Intangible Plant**	
2	303.0	Miscellaneous Intangible	2.75%
3		**Transmission Plant**	
4	352	Structures & Improvements	2.05%
5	353	Station Equipment	1.69%
6	354	Towers and Fixtures	1.32%
7	355	Poles & Fixtures	1.88%
8	356	O/H Conductor & Devices	1.73%
9	357	Underground Conduit	1.66%
10	358	Underground Cables	2.09%
11	359	Roads and Trails	1.11%
12		**Distribution Plant**	
13	361	Distribution Plant Structures	1.52%
14	362	Distribution Plant Station Equipment	1.38%
15		**General Plant**	
16	390	Structures and Improvements	1.46%
17	391	**OFFICE FURNITURE EQUIPMENT**	
18	391.1	Personal Computers	9.53%
19	391.11	Furniture	9.53%
20	391.12	Office Equipment	9.53%
21	391.13	Computer Hardware	9.53%
22	391.14	LRS Office Equipment	9.53%
23	391.15	EMS Office Equipment	9.53%
24	391.16	EMS Computer Equipment	9.53%
25	391.17	CO41 OWNED AT JMS	9.53%
26	391.18	SOFTWARE	9.53%
27	391.19	Plains Furniture and Equipment	9.53%
28	392	**TRANSPORTATION EQUIPMENT**	
29	392.1	Transportation Equipment	2.93%
30	392.11	Airplane	2.93%
31	392.12	Snow Cats/Trailers	2.93%
32	392.13	LRSVehicles	2.93%
33	392.14	Plains Transportation Equipment	2.93%
34	392.15	Diesel Trucks	2.93%
35	392.16	Craig- Fuel Vehicles	2.93%
36	392.17	Craig- Maintenance Vehicles	2.93%
37	392.18	Craig- Operating Vehicles	2.93%
38	392.19	Pickups	2.93%
39	392.2	Autos	2.93%
40	392.21	Heavy Duty Trucks	2.93%
41	393	Stores Equipment	3.17%
42	394	Tools, Shop and Garage Equipment	2.35%
43	395	Lab & Testing Equipment	4.67%
44	396	Power Operated Equipment	2.29%
45	397	Communications Equipment	4.53%
46	398	Miscellaneous	5.94%

47 Notes:
48 A.) These rates are fixed and cannot be changed absent authorization from FERC via a Section 205 or 206 filing.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Reconciliation Adjustments to ATRR

Data: Year Ending December 31, 2018

Reconciliation Adjustments To ATRR

A	B	C	D	E	F	G	H	I	J
Line	ERROR IDENTIFICATION	Formula Reference	Rate Year (Note A)	Incorrect Amount	Correct Amount	Difference (Cred)/ Chg	Impact on ATRR (Cred)/Chg	Calculated Interest (Note B)	Total Adjustment to ATRR
1								$ -	$ -
2									0
3									0
4									0
5									0
6	**Total Adjustment to Gross ATRR:**								$ -

Tri-State Generation and Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE
Reconciliation Adjustments to ATRR
Data: Year Ending December 31, 2018

A	B	C	D	E	F	G	H	I	J

Other Reconciliation Adjustments To ATRR

Line	ERROR IDENTIFICATION	Formula Reference	Rate Year (Note A)	Incorrect Amount	Correct Amount	Difference (Cred)/ Chg	Impact on ATRR (Cred)/Chg	Calculated Interest (Note B)	Total Adjustment to ATRR
7									0
8									0
9									0
10									0
11									0
12	**Total Adjustment to ATRR:**								0

13 **Interest calculation for Item #1**

14	Quarter	Service Month	FERC Monthly Interest Rate	Monthly Interest	Monthly Over/Under Collections & Amortization (1/12 of Annual True Up Amount) (Note C)	Total Balance (quarterly compounding)	Total Balance Prior Month Col G + Current Month Col D + Col E
15	A	B	C	D = C x F	E	F	G
16				$ -	$ -	$ -	$ -
17				$ -	$ -	$ -	$ -
18				$ -	$ -	$ -	$ -
19	*			$ -	$ -	$ -	$ -
20				$ -	$ -	$ -	$ -
21				$ -	$ -	$ -	$ -
22	*			$ -	$ -	$ -	$ -
23				$ -	$ -	$ -	$ -
24				$ -	$ -	$ -	$ -

Tri-State Generation and Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE
Reconciliation Adjustments to ATRR
Data: Year Ending December 31, 2018

A		B	C	D	E	F	G	H	I	J
25	*		$ -	$ -	$ -	$ -				
26			$ -	$ -	$ -	$ -				
27			$ -	$ -	$ -	$ -				
28		Total Interest	$ -							
29		Total True-up Amount	$ -							
30	*	Total True Up Amount with Interest	$ -							

Tri-State Generation and Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE
Wages
Data: Year Ending December 31, 2018

A Line	B Function	C Direct Labor	D Sick, Vacation, Option, Holiday	E Benefits	F Total Labor Expense
1	**Expenses**				
2	Production	$ 35,978,433	$ 5,218,470	$ 13,305,390	$ 54,502,293
3	Transmission	$ 31,356,873	$ 4,669,176	$ 18,168,457	$ 54,194,507
4	Distribution	$ 271,868	$ 40,877	$ 152,954	$ 465,699
5	Customer Accounting	$ 230,613	$ 36,898	$ 138,368	$ 405,878
6	Customer Service	$ 9,557	$ 1,423	$ 5,391	$ 16,371
7	Customer Sales	$ -	$ -	$ -	$ -
8	Total	$ 67,847,343	$ 9,966,844	$ 31,770,560	$ 109,584,747
9		61.9131%	9.0951%	28.9918%	100.0000%
10	**Transmission O&M - Acct 561 - Load Dispatch**				
11	561.00 Operations	$ 3,895,841	$ 537,708	$ 2,060,549	$ 6,494,098
12	561.20 Transmission	$ -	$ -	$ -	$ -
13	561.25 South Trans	$ -	$ -	$ -	$ -
14	Total	$ 3,895,841	$ 537,708	$ 2,060,549	$ 6,494,098
15	Notes:				
16	A.) Source: Company Records				

Tri-State Generation & Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Annual Depreciation Expense
Data: Year Ending December 31, 2018

A Line	B Account	C Description	D BOY Amount	E EOY Amount	F Transmission Amount (Avg)	G Depreciation Rate	H Depreciation Expense
1		**Transmission Plant**					
2	350	Land and Land Rights	$100,359,540	$102,903,387	$101,631,463.32	N/A	
3	352	Structures & Improvements	$27,358,931	$32,368,393	$29,863,662	2.05%	$612,205
4	353	Station Equipment	$315,779,381	$336,182,019	$325,980,700	1.69%	$5,509,074
5	354	Towers and Fixtures	$84,632,641	$84,632,641	$84,632,641	1.32%	$1,117,151
6	355	Poles & Fixtures	$143,384,557	$143,384,557	$143,384,557	1.88%	$2,695,630
7	356	O/H Conductor & Devices	$203,537,117	$203,634,558	$203,585,837	1.73%	$3,522,035
8	357	Underground Conduit	$9,634,122	$9,634,122	$9,634,122	1.66%	$159,926
9	358	Underground Cables	$5,750,709	$5,750,709	$5,750,709	2.09%	$120,190
10	359	Roads and Trails	$8,907,875	$9,008,142	$8,958,008.82	1.11%	$99,434
11		Total Transmission Depreciation Expense	$899,344,872	$927,498,528	$913,421,700	**1.69%**	$13,835,645

A Line	B Account	C Description	D Total Company BOY Amount	E Total Company EOY Amount	F Total Company Amount (Avg)	G T-Wage Allocation Factor	H West Amount	I Depreciation Rate	J Depreciation Expense
12		**General Plant**							
13	390	Structures and Improvements	$70,780,714	$70,763,097	$70,771,905.25	31.88%	$22,562,877	1.46%	$329,418
14	391.1	Personal Computers	$41,782,450	$45,283,293	$43,532,871.48	31.88%	$13,878,767	9.53%	$1,322,647
15	391.11	Furniture	$5,629,357	$5,604,790	$5,617,073.45	31.88%	$1,790,786	9.53%	$170,662
16	391.12	Office Equipment	$2,517,136	$2,517,136	$2,517,135.71	31.88%	$802,491	9.53%	$76,477
17	391.13	Computer Hardware	$9,390,224	$9,390,224	$9,390,224.10	31.88%	$2,993,709	9.53%	$285,300
18	391.14	LRS Office Equipment	$129,222	$143,901	$136,561.59	31.88%	$43,537	9.53%	$4,149
19	391.15	EMS Office Equipment	$24,836	$24,836	$24,835.60	31.88%	$7,918	9.53%	$755
20	391.16	EMS Computer Equipment	$4,983,177	$4,983,177	$4,983,176.69	31.88%	$1,588,693	9.53%	$151,402
21	391.17	CO41 OWNED AT JMS	$131,402	$131,402	$131,402	31.88%	$41,892	9.53%	$3,992
22	391.18	SOFTWARE	$60,524,876	$60,424,469	$60,474,673	31.88%	$19,280,004	9.53%	$1,837,384
23	391.19	Plains Furniture and Equipment	$10,832,216	$2,228,027	$6,530,121	31.88%	$2,081,876	9.53%	$198,403
24	392.1	Transportation Equipment	$387,292	$379,792	$383,542	31.88%	$122,277	2.93%	$3,583
25	392.11	Airplane	$5,275,410	$5,275,410	$5,275,410	31.88%	$1,681,860	2.93%	$49,278
26	392.12	Snow Cats/Trailers	$2,714,286	$2,654,345	$2,684,315	31.88%	$855,790	2.93%	$25,075
27	392.13	LRSVehicles	$1,159,752	$1,253,543	$1,206,648	31.88%	$384,693	2.93%	$11,271
28	392.14	Plains Transportation Equipment	$3,036,648	$3,036,648	$3,036,648	31.88%	$968,117	2.93%	$28,366
29	392.15	Diesel Trucks	$1,496,988	$1,256,708	$1,376,848	31.88%	$438,955	2.93%	$12,861
30	392.16	Craig- Fuel Vehicles	$46,097	$46,097	$46,097	31.88%	$14,696	2.93%	$431
31	392.17	Craig- Maintenance Vehicles	$173,103	$173,103	$173,103	31.88%	$55,187	2.93%	$1,617
32	392.18	Craig- Operating Vehicles	$326,429	$326,429	$326,429	31.88%	$104,069	2.93%	$3,049
33	392.19	Pickups	$18,402,546	$20,410,026	$19,406,286	31.88%	$6,186,942	2.93%	$181,277
34	392.2	Autos	$2,315,404	$2,140,603	$2,228,004	31.88%	$710,313	2.93%	$20,812
35	392.21	Heavy Duty Trucks	$7,006,351	$6,346,163	$6,676,257	31.88%	$2,128,466	2.93%	$62,364
36	393	Stores Equipment	$1,434,139	$1,474,025	$1,454,082	31.88%	$463,578	3.17%	$14,695
37	394	Tools, Shop and Garage Equipment	$10,038,158	$10,190,694	$10,114,426	31.88%	$3,224,592	2.35%	$75,778
38	395	Lab & Testing Equipment	$14,566,845	$14,701,803	$14,634,324	31.88%	$4,665,587	4.67%	$217,883
39	396	Power Operated Equipment	$31,528,080	$33,134,561	$32,331,320	31.88%	$10,307,587	2.29%	$236,044
40	397	Communications Equipment	$152,444,837	$152,047,089	$152,245,963	31.88%	$48,537,720	4.53%	$2,198,759
41	398	Miscellaneous	$2,487,410	$2,486,304	$2,486,857	31.88%	$792,838	5.94%	$47,095
42		Total General Depreciation Expense	$461,565,382	$458,827,693	$460,196,538		$146,715,815		$7,570,828
43		**Intangible Plant**							
44	303.0	Miscellaneous Intangible	$143,812,569	$144,124,319	$143,968,443.75	31.88%	$45,898,754	2.75%	$1,262,216
45		Total Intangible Amortization Expense	$143,812,569	$144,124,319	$143,968,444		$45,898,754		$1,262,216

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Other Revenue
Data: Year Ending December 31, 2018

A Line	B Account	C Description	D Total Company	E East ATRR	F West ATRR	G Other
1	45400	RENT FROM ELECTRIC PROPERTY	$ 2,704,002	$ 22,582	$ 140,587	$ 2,540,834
2	45410	RENT - LEASING CONTRACT	$ 529,531	$ -	$ 529,531	$ (0)
3	45415	RENT FROM SOUTHERN ELECTRIC PROPERTY	$ -	$ -	$ -	$ -
4	45600	OTHER ELECTRIC REVENUES	$ 5,294,118	$ -	$ 1,477,145	$ 3,816,973
5	45601	OTHER ELECTRIC REVENUES - TSP WHEELING	$ -	$ -	$ -	$ -
6	45610-45612	OTHER ELECTRIC REVENUES - ADVANCED REVENUE AMORTIZATION	$ -	$ -	$ -	$ -
7	45620-45623	OTHER ELECTRIC REVENUES - AGGREGATE NTWK SVC	$ -	$ -	$ -	$ -
8	45690	OTHER ELECTRIC REVENUES - WHEELING	$ (647,607)	$ -	$ -	$ (647,607)
9	45691	OTHER ELECTRIC REVENUE - GFAs	$ 3,017,993	$ -	$ 3,017,993	$ -
10	45692	OTHER ELECTRIC REVENUE	$ -	$ -	$ -	$ -
11	45693	SOUTHERN WHEELING REVENUES	$ (5,414,893)	$ -	$ -	$ (5,414,893)
12	45695-45698	OTHER ELECTRIC REVENUE-OATT	$ 6,569,901	$ -	$ -	$ 6,569,901
13	45630	OTHER ELECTRIC REVENUE - GAIN/LOSS ON SALE OF NAT'L GAS	$ -	$ -	$ -	$ -
14	45420	RENT FROM ELECTRIC PROPERTY	$ -	$ -	$ -	$ -
15	45425	RENT FROM ELECTRIC PROPERTY	$ -	$ -	$ -	$ -
16	45660	OTHER ELECTRIC REVENUE - ADMINISTRATIVE FEE - TSR	$ -	$ -	$ -	$ -
17	45900	REVENUE - SALE OF NON-MEMBER RECS	$ -	$ -	$ -	$ -
18	45910	REVENUE - SALE OF MEMBER REC	$ -	$ -	$ -	$ -
19	45616	REVENUES FROM TRANSMISSION OF ELECTRICITY OF OTHERS-ST FIRM&NON-FIRM	$ 7,919,961	$ -	$ 7,919,961	$ (0)
20	45615	REVENUES FROM TRANSMISSION OF ELECTRICITY OF OTHERS-LT FIRM	$ 1,150,558	$ -	$ -	$ 1,150,558
21		Total Other Operating Revenue and Income	$ 21,123,563	$ 22,582	$ 13,085,217	8,015,765
22						
23		**Summary:**	**Total**	**East**	**West**	**Other**
24	454	RENT FROM ELECTRIC PROPERTY	$ 3,233,533	$ 22,582	$ 670,118	$ 2,540,833
25	456	OTHER ELECTRIC REVENUE - ADMINISTRATIVE FEE - TSR	$ -		$ -	$ -
26	456	REVENUES FROM TRANSMISSION OF ELECTRICITY OF OTHERS INCLUDING -ST FIRM & NON-FIRM	$ 13,214,079	$ -	$ 9,397,106	$ 3,816,973
27	456	OTHER ELECTRIC REVENUE - GFAs	$ 3,017,993	$ -	$ 3,017,993	$ -
28	456	OTHER ELECTRIC REVENUE	$ 1,657,959	$ -	$ -	$ 1,657,959
29		OTHER REVENUES	$ 21,123,563	$ 22,582	$ 13,085,217	$ 8,015,765

30 Notes:

31 A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Plant Held for Future Use
Data: Year Ending December 31, 2018

				BOY Investment			EOY Investment			Average Investment		
A	B	C	D	E	F	G	H	I	J	K	L	M
Line	Facility No.	Asset No.	Description	Total	West	East	Total	West	East	Total	West	East
1			Production Future Use Assets	$ 74,369,029	$ 74,369,029	$ -	$ 74,369,029	$ 74,369,029	$ -	$ 74,369,029	$ 74,369,029	$ -
2	3112		LAND NORWOOD SUBSTATION SITE	$ 100,336	$ 100,336	$ -	$ 100,336	$ 100,336	$ -	$ 100,336	$ 100,336	$ -
3	1556		FUTURE USE-SAN LUIS TRANS SUB	$ 29,514	$ 29,514	$ -	$ 29,514	$ 29,514	$ -	$ 29,514	$ 29,514	$ -
4	1567		FUTURE USE NORTH FORK 345/115kV SUB SITE	$ 26,236.25	$ 26,236	$ -	$ 26,236	$ 26,236	$ -	$ 26,236	$ 26,236	
5	1575		FUTURE USE CALUMET SUB SITE	$ 39,699.09	$ 39,699	$ -	$ 39,699	$ 39,699	$ -	$ 39,699	$ 39,699	$ -
6	3862		EASEMENT ON UTE RESERVATION FOR 115KV LINE	$ 55,368	$ 55,368	$ -	$ 55,368	$ 55,368	$ -	$ 55,368	$ 55,368	$ -
7	1935		UTE SUBSTATION ON UTE RESERVATION	$ 15,274	$ 15,274	$ -	$ 15,274	$ 15,274	$ -	$ 15,274	$ 15,274	$ -
8	51		LOT 6 POLE CREEK 35.20 ACREAS	$ 259,549	$ 259,549	$ -	$ 259,549	$ 259,549	$ -	$ 259,549	$ 259,549	$ -
9	51		LOT 7 POLE CREEK 35.20 ACREAS	$ 259,549	$ 259,549	$ -	$ -	$ -	$ -	$ 129,775	$ 129,775	$ -
10	1410		BRADSHAW, LARRY A. AND BARBARA R. FARM	$ 348,040	$ 348,040	$ -	$ 348,040	$ 348,040	$ -	$ 348,040	$ 348,040	$ -
11	1410		BRADSHAW, LARRY A. AND BARBARA R. FARM	$ 149,536	$ 149,536	$ -	$ 149,536	$ 149,536	$ -	$ 149,536	$ 149,536	$ -
12	1411		125 MILE ROAD FARM	$ 1,228,221	$ 1,228,221	$ -	$ 1,228,221	$ 1,228,221	$ -	$ 1,228,221	$ 1,228,221	$ -
13	1412		MONKS, WILLIAM FARM	$ 330,865	$ 330,865	$ -	$ 330,865	$ 330,865	$ -	$ 330,865	$ 330,865	$ -
14					$ -	$ -		$ -	$ -	$ -	$ -	$ -
15					$ -	$ -		$ -	$ -	$ -	$ -	$ -
16			Subtotal Transmission Future Use Assets	$ 2,842,188	$ 2,842,188	$ -	$ 2,582,639	$ 2,582,639	$ -	$ 2,712,413	$ 2,712,413	$ -
17			Distribution Future Use Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18			General Plant Future Use Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19			Intangible Plant Future Use Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20			Total Plant Held for Future Use	$ 77,211,216	$ 77,211,216	$ -	$ 76,951,667	$ 76,951,667	$ -	$ 77,081,442	$ 77,081,442	$ -

21 Notes:
22 A.) Source: Company Records
23 B.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Account 565 - Transmission of Electricity by Others

Data: Year Ending December 31, 2018

A Line	B Account (A)	C Account Description	D Total Company	E East	F West
1	56500-56515	TRANSMISSION OF ELECTRICITY BY OTHERS	$ 42,072,444	$ 1,689,185	$ 40,383,259
2	56520	WHEELING - NONMEMBER LOADS	$ -	$ -	$ -
3	56525-56535	TRANSMISSION OF ELECTRICITY BY OTHERS - OATT	$ 9,698,946	$ -	$ 9,698,946
4	56550-56555	TRANSMISSION OF ELECTRICITY BY OTHERS - NTWK SVC	$ 111,903,401	$ -	$ 111,903,401
5	56560-56565	TRANSMISSION OF ELECTRICITY BY OTHERS - AGGREGATE NTWK SVC - OFFSET	$ (111,903,401)	$ -	$ (111,903,401)
6					
7		Total Account 565	**$ 51,771,390**	**$ 1,689,185**	**50,082,205**

8 Notes:

9 A.) Source: Company Records.

10 B.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Tri-State Generation & Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Account 575/576 Expenses
Data: Year Ending December 31, 2018

A Line	B Account No.	C Description	D Annual Expense Amount	E % Included in West	F West Amount
	575.1-575.8 RTO/ISO Expense - Operation				
1a					-
1b					-
…					-
2	**Total 575.1-575.8 RTO/ISO Expense - Operation (sum lines 1a-1xx) (Note A)**		-		-
	576.1-576.5 RTO/ISO Expense - Maintenance				
3a					-
3b					-
…					-
4	**576.1-576.5 RTO/ISO Expense - Maintenance (sum lines 3a-3xx) (Note B)**		-		-

5 Notes:
6 A.) The total on line 2, column D must reconcile to the amounts shown on RUSFOR.
7 B.) The total on line 4, column D must reconcile to the amounts shown on RUSFOR.
8 C.) Amounts listed on lines 1a-1xx and 3a-3xx are only eligible for inclusion in ATRR following a change in accounting procedures to the RUS Form 12 or Uniform System of Accounts, which would classify amounts in these accounts as eligible for transmission rate recovery. To the extent that this occurs, Tri-State may file a single-issue Section 205 filing with the Commission to seek recovery of these amounts in rates. Tri-State may not include any costs absent authorization from FERC via a Section 205 or 206 filing.
9 D.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Completed Construction Not Classified
Data: Year Ending December 31, 2018

A	B	C	D		E		F	G	H	I		J
Line	Fac ID	Facility Name	BOY Balance		EOY Balance		100% West	0% West	West Portion if Less than 100%	Amount		Comments
1							Completed Not Classified Total:			$94,876,195		
2	3936	ALAMOGORDO-TNP LINE	$	6,408	$	6,408	X			$	6,408	
3	3936	ALAMOGORDO-TNP LINE	$	-	$	33,780	X			$	16,890	
4	2018	ALAMOGORDO SUBSTATION	$	-	$	184,523	X			$	92,262	
5	2139	ALAMOGORDO SUBSTATION	$	287,066	$	287,986	X			$	287,526	
6	2003	ALGODONES SWITCHING STATION	$	330,763	$	-	X			$	165,382	
7	4122	ALTA LUNA-CABALLO LINE	$	-	$	3,034,506	X			$	1,517,253	
8	3778	ALVIN-SANDHILLS LINE	$	230,193	$	230,193	X			$	230,193	
9	3805	ALVIN-WAUNETA LINE	$	86,371	$	86,371	X			$	86,371	
10	3805	ALVIN-WAUNETA LINE	$	2,766	$	2,766	X			$	2,766	
11	3969	ANASAZI-DOE CANYON LINE	$	30,585	$	30,702	X			$	30,644	
12	4131	ANASAZI-YELLOW JACKET II LINE	$	-	$	5,806	X			$	2,903	
13	1789	AULT SUBSTATION	$	640,534	$	497,689	X			$	569,112	
14	3614	AXIAL BASIN-MEEKER LINE	$	226,406	$	226,406	X			$	226,406	
15	3614	AXIAL BASIN-MEEKER LINE	$	-	$	316,016	X			$	158,008	
16	3614	AXIAL BASIN-MEEKER LINE	$	471,267	$	-	X			$	235,634	
17	1539	AXIAL BASIN SUBSTATION	$	104,309	$	104,309	X			$	104,309	
18	1539	AXIAL BASIN SUBSTATION	$	-	$	1,316,203	X			$	658,102	
19	1650	BASIN SUBSTATION	$	100,254	$	-	X			$	50,127	
20	1616	BEAVER CREEK 230 KV SUBSTATION	$	162,485	$	162,485	X			$	162,485	
21	3784	BEAVER CREEK-BEAVER CREEK LINE	$	1,798	$	1,798	X			$	1,798	
22	4135	BERNARDO-SOCORRO LINE	$	-	$	67,170	X			$	33,585	
23	3715	BIG SANDY-LANDSMAN CREEK LINE	$	2,019,126	$	2,019,126	X			$	2,019,126	
24	3715	BIG SANDY-LANDSMAN CREEK LINE	$	244,658	$	245,624	X			$	245,141	
25	1608	BIG SANDY SUBSTATION	$	174,378	$	174,378	X			$	174,378	
26	1608	BIG SANDY SUBSTATION	$	-	$	45,769	X			$	22,885	
27	3906	BLACK LAKE-SPRINGER LINE LINE	$	35,000	$	35,000	X			$	35,000	
28	3797	BLACK SQUIRREL-FULLER LINE	$	83,508	$	83,508	X			$	83,508	
29	1515	BLACK SQUIRREL SUBSTATION	$	17,577	$	17,577	X			$	17,577	
30	3963	BLACK SQUIRREL-MERIDIAN RANCH SUB LINE	$	52,326	$	52,326	X			$	52,326	
31	641	BLUEWATER SUBSTATION	$	30,714	$	30,714	X			$	30,714	
32	641	BLUEWATER SUBSTATION	$	-	$	298	X			$	149	
33	641	BLUEWATER SUBSTATION	$	531,734	$	558,644	X			$	545,189	
34	2093	BLUEWATER SUBSTATION	$	649,738	$	650,178	X			$	649,958	
35	3641	BODO-HESPERUS DBL CKT LINE	$	-	$	127,047	X			$	63,524	
36	3762	BONNEY CREEK-BURLING-N LINE	$	87,771	$	87,771	X			$	87,771	

37	3586	BOONE-LA JUNTA LINE	$	-	$	323,883	X	$	161,942
38	3530	BOONE-LAMAR LINE	$	177,109	$	177,503	X	$	177,306
39	3530	BOONE-LAMAR LINE	$	-	$	29,553	X	$	14,777
40	1534	BOONE SUBSTATION	$	67,142	$	67,142	X	$	67,142
41	1665	BOYD SUBSTATION	$	170,987	$	231,615	X	$	201,301
42	1665	BOYD SUBSTATION	$	170,987	$	-	X	$	85,494
43	2043	BROMLEY SUBSTATION	$	816,534	$	816,534	X	$	816,534
44	2043	BROMLEY SUBSTATION	$	816,534	$	-	X	$	408,267
45	2043	BROMLEY SUBSTATION	$	1,503,431	$	-	X	$	751,716
46	1531	BULLOCK SUBSTATION	$	368,780	$	368,780	X	$	368,780
47	1611	BURLINGTON SUBSTATION	$	29,026	$	29,026	X	$	29,026
48	3764	BURLINGTON-BURLINGTON LINE	$	-	$	35,455	X	$	17,728
49	3763	BURLINGTON-BURLINGTON LINE	$	66,314	$	66,314	X	$	66,314
50	1872	BURRO BRIDGE SUBSTATION	$	307,594	$	303,751	X	$	305,673
51	1582	BURRO CANYON SUBSTATION	$	238,430	$	238,430	X	$	238,430
52	1582	BURRO CANYON SUBSTATION	$	97,421	$	97,421	X	$	97,421
53	1582	BURRO CANYON SUBSTATION	$	74,511	$	-	X	$	37,256
54	3979	CABALLO-MIMBRES LINE	$	104,112	$	104,112	X	$	104,112
55	3979	CABALLO-MIMBRES LINE	$	-	$	5,103	X	$	2,552
56	1564	CAHONE SUBSTATION	$	17,176	$	17,176	X	$	17,176
57	1564	CAHONE SUBSTATION	$	285,127	$	312,289	X	$	298,708
58	3626	CAHONE-EMPIRE LINE	$	-	$	211,381	X	$	105,691
59	3968	CAHONE-DOE CANYON LINE	$	21,995	$	22,112	X	$	22,054
60	4114	CARMEL-ZINZER LINE	$	3,365,378	$	3,365,378	X	$	3,365,378
61	1540	CASCADE SUBSTATION	$	29,837	$	28,977	X	$	29,407
62	3845	CASCADE-SILVERTON TAP LINE	$	160,818	$	160,818	X	$	160,818
63	4045	CEMEX-DOWE FLATS LINE	$	80,446	$	80,446	X	$	80,446
64	2021	CLAPHAM SUBSTATION	$	190,622	$	190,622	X	$	190,622
65	2021	CLAPHAM SUBSTATION	$	-	$	590,082	X	$	295,041
66	2021	CLAPHAM SUBSTATION	$	36,778	$	-	X	$	18,389
67	3806	COMANCHE-WALSENBURG LINE	$	-	$	124,501	X	$	62,251
68	4054	CORTEZ PIPELINE TAP-MAIN SWITCH LINE	$	-	$	4,247	X	$	2,124
69	4052	CORTEZ PIPELINE TAP-TOWAOC CANAL TAP LI	$	-	$	3,961	X	$	1,981
70	3819	CORTEZ-EMPIRE LINE	$	6,779	$	6,779	X	$	6,779
71	4139	COW CANYON-HOVENWEEP LINE	$	-	$	4,914	X	$	2,457
72	4140	COW CANYON-YELLOW JACKET LL LINE	$	-	$	4,097	X	$	2,049
73	1560	CRAIG SWITCHING STATION	$	-	$	7,864	X	$	3,932
74	1562	CRAIG SWITCHING STATION	$	-	$	3,810	X	$	1,905
75	1562	CRAIG SWITCHING STATION	$	-	$	7,024	X	$	3,512
76	1559	CRAIG SWITCHING STATION	$	223,977	$	-	X	$	111,989
77	3533	CRAIG-HAYDEN TAP LINE	$	448	$	448	X	$	448
78	3532	CRAIG-RIFLE LINE	$	3,880	$	3,880	X	$	3,880
79	3858	DACONO-ERIE LINE	$	14,433	$	14,433	X	$	14,433
80	4088	DAVIS-GREENHOUSE LINE	$	5,964,257	$	5,980,353	X	$	5,972,305
81	1618	DEERING LAKE SWITCHING STATION	$	7,283,610	$	-	X	$	3,641,805
82	3716	DEERING LAKE-NORTH YUMA LINE	$	189,997	$	189,997	X	$	189,997
83	2052	DEL CAMINO SWITCHING STATION	$	9,436	$	-	X	$	4,718
84	2052	DEL CAMINO SWITCHING STATION	$	33,834	$	-	X	$	16,917
85	3856	DEL CAMINO-RINN VALLEY LINE	$	91,337	$	91,337	X	$	91,337
86	3856	DEL CAMINO-RINN VALLEY LINE	$	585,253	$	585,253	X	$	585,253
87	1647	DIFFICULTY SUBSTATION	$	39,282	$	-	X	$	19,641
88	3921	DONA ANA-ALAMOGORDO LINE	$	303,035	$	303,202	X	$	303,119

89	3921	DONA ANA-ALAMOGORDO LINE	$	-	$	31,569	X		$	15,785
90	2008	DONA ANA SWITCHING STATION	$	63,912	$	63,912	X		$	63,912
91	4044	DOWE FLATS-LYONS TAP LINE	$	47,539	$	47,539	X		$	47,539
92	3967	E MONTROSE-PEACH VALLEY LINE	$	13,971	$	13,971	X		$	13,971
93	1721	ECKLEY SUBSTATION	$	85,468	$	85,468	X		$	85,468
94	1721	ECKLEY SUBSTATION	$	-	$	696,108	X		$	348,054
95	1721	ECKLEY SUBSTATION	$	30,830	$	-	X		$	15,415
96	3920	ELEPHANT BUTTE-LAS CRUCES LINE	$	578,491	$	577,687	X		$	578,089
97	3920	ELEPHANT BUTTE-LAS CRUCES LINE	$	1,600,334	$	1,600,334	X		$	1,600,334
98	3919	ELEPHANT BUTTE-SOCORRO LINE	$	601,010	$	602,055	X		$	601,533
99	1634	EMIGRANT SWITCHING STATION	$	265,948	$	265,948	X		$	265,948
100	1634	EMIGRANT SWITCHING STATION	$	28,194	$	-	X		$	14,097
101	3861	EMIL ANDERSON-FOREST LAKES LINE	$	-	$	591,779	X		$	295,890
102	3508	EMPIRE-LOST CANYON LINE	$	63	$	63	X		$	63
103	2087	ERIE SUBSTATION	$	7,689	$	7,689	X		$	7,689
104	2087	ERIE SUBSTATION	$	-	$	126,385	X		$	63,193
105	3809	FRASER (METTLER)-MILL LINE	$	137,787	$	137,905	X		$	137,846
106	3809	FRASER (METTLER)-MILL LINE	$	-	$	(486)	X		$	(243)
107	3708	FRASER (METTLER)-WINDY GAP LINE	$	-	$	48,972	X		$	24,486
108	3660	GARNET MESA TAP-SUBSTATION LINE	$	112,391	$	114,854	X		$	113,623
109	1729	GEESEN SUBSTATION	$	1,552,156	$	1,552,156	X		$	1,552,156
110	3953	GLADSTONE-CO/NM STATE LINE LINE	$	23,622	$	23,622	X		$	23,622
111	3982	GLADSTONE-SPRINGER LINE	$	-	$	23,983	X		$	11,992
112	3975	GOODMAN POINT-MAIN SWITCH LINE	$	-	$	4,736	X		$	2,368
113	3713	GORE PASS-WINDY GAP LINE	$	-	$	47,209	X		$	23,605
114	1613	GORE PASS SUBSTATION	$	722,355	$	722,355	X		$	722,355
115	1613	GORE PASS SUBSTATION	$	388,676	$	405,264	X		$	396,970
116	3955	GRANBY PUMPING PLANT-WINDY GAP LINE	$	-	$	11,664,641	X		$	5,832,321
117	3514	GRAND JUNCTION-MONTROSE LINE	$	566,320	$	566,698	X		$	566,509
118	3514	GRAND JUNCTION-MONTROSE LINE	$	-	$	400,657	X		$	200,329
119	2010	GRANTS SWITCHING STATION	$	13,355	$	15,231	X		$	14,293
120	4095	GREENHOUSE-HENRY LAKE LINE	$	5,650,060	$	5,659,758	X		$	5,654,909
121	4089	GREENHOUSE-JM SHAFER LINE	$	87,971	$	-	X		$	43,986
122	2204	GREENHOUSE SUBSTATION	$	13,863,561	$	-	X		$	6,931,781
123	3834	GRESHAM-BLACK FOREST TAP LINE	$	30,890	$	30,890	X		$	30,890
124	1505	HAPPY CANYON SUBSTATION	$	16,679	$	16,679	X		$	16,679
125	1505	HAPPY CANYON SUBSTATION	$	2,880,849	$	-	X		$	1,440,425
126	3528	HAYDEN SUB-AXIAL BASIN LINE	$	482,901	$	483,156	X		$	483,029
127	3791	HELL CREEK TAP-LIBERTY LINE	$	-	$	18,850	X		$	9,425
128	2041	HENRY LAKE SUBSTATION	$	128,284	$	-	X		$	64,142
129	3904	HERNANDEZ-OJO CALIENTE TAP LINE	$	-	$	219,056	X		$	109,528
130	1565	HESPERUS SUBSTATION	$	92,298	$	-	X		$	46,149
131	1565	HESPERUS SUBSTATION	$	172,468	$	-	X		$	86,234
132	2241	HESPERUS SUBSTATION	$	-	$	8,437,123	X		$	4,218,562
133	3506	HESPERUS-NM STATE LINE	$	-	$	115,108	X		$	57,554
134	3946	HIDALGO-PYRAMID LINE	$	7,137	$	7,137	X		$	7,137
135	3510	HIDALGO-PYRAMID LINE	$	-	$	315,858	X		$	157,929
136	3927	HOLLOMAN TAP-ALAMOGORDO LINE	$	-	$	13,167	X		$	6,584
137	1670	HORSETOOTH SUBSTATION	$	27,449	$	27,449	X		$	27,449
138	3008	HOT SPRINGS TAP	$	74,040	$	74,040	X		$	74,040
139	1506	HOTCHKISS SUBSTATION	$	19,068	$	19,068	X		$	19,068
140	1506	HOTCHKISS SUBSTATION	$	44,033	$	-	X		$	22,017

141	3644	HOTCHKISS-NORTH FORK LINE	$	98,090	$	98,090	X	$	98,090
142	3972	HOVENWEEP-SAND CANYON LINE	$	-	$	4,478	X	$	2,239
143	2207	JM SHAFER SUBSTATION	$	2,571,405	$	2,572,855	X	$	2,572,130
144	3831	JOES-ARICKAREE LINE	$	-	$	271,848	X	$	135,924
145	1592	JUANITA SUBSTATION	$	61,822	$	61,822	X	$	61,822
146	1592	JUANITA SUBSTATION	$	528,177	$	-	X	$	264,089
147	4083	KEOTA-REDBOX LINE	$	3,939,225	$	3,939,225	X	$	3,939,225
148	1911	KREMMLING SUBSTATION	$	-	$	348,997	X	$	174,499
149	3631	LAJUNTA-WILLOW CREEK LINE	$	-	$	633,955	X	$	316,978
150	3631	LAJUNTA-WILLOW CREEK LINE	$	190,060	$	190,060	X	$	190,060
151	2140	LANDSMAN CREEK SWITCHING STATION	$	6,080	$	6,080	X	$	6,080
152	1744	LAPORTE SUBSTATION	$	167,354	$	167,354	X	$	167,354
153	1744	LAPORTE SUBSTATION	$	120,396	$	130,581	X	$	125,489
154	1672	LIBERTY SUBSTATION	$	124,424	$	124,424	X	$	124,424
155	1549	LOST CANYON SUBSTATION	$	731,602	$	731,602	X	$	731,602
156	1549	LOST CANYON SUBSTATION	$	38,725	$	30,142	X	$	34,434
157	1549	LOST CANYON SUBSTATION	$	1,001,744	$	1,001,744	X	$	1,001,744
158	4050	LOST CANYON-TOWAOC CANAL TAP LINE	$	-	$	6,439	X	$	3,220
159	3742	LOVELL-BIG GEORGE LINE	$	-	$	357,104	X	$	178,552
160	3742	LOVELL-BIG GEORGE LINE	$	152,064	$	152,630	X	$	152,347
161	3855	LUDLOW TAP-BURRO CANYON LINE	$	315,473	$	315,473	X	$	315,473
162	3855	LUDLOW TAP-BURRO CANYON LINE	$	973	$	973	X	$	973
163	4141	MAIN SWITCH-MOQUI C LINE	$	-	$	4,764	X	$	2,382
164	3840	MANCOS TAP-LOST CANYON LINE	$	153,243	$	153,879	X	$	153,561
165	1543	MEEKER SUBSTATION	$	571,151	$	-	X	$	285,576
166	2104	MEEKER SWITCHING STATION	$	57,797	$	-	X	$	28,899
167	3529	MEEKER-RIFLE LINE	$	-	$	271,436	X	$	135,718
168	3529	MEEKER-RIFLE LINE	$	-	$	472,831	X	$	236,416
169	3529	MEEKER-RIFLE LINE	$	-	$	57,830	X	$	28,915
170	1614	MIDWAY SUBSTATION	$	20,843	$	-	X	$	10,422
171	3587	MIDWAY-BOONE LINE	$	22,989	$	22,989	X	$	22,989
172	2209	MONTROSE SUBSTATION	$	327,152	$	359,131	X	$	343,142
173	1597	MONTROSE SUBSTATION	$	453,926	$	-	X	$	226,963
174	3515	MONTROSE-HAPPY CANYON LINE	$	-	$	10,857	X	$	5,429
175	3519	MONTROSE-NUCLA LINE	$	37,905	$	37,905	X	$	37,905
176	1753	MONUMENT SUBSTATION	$	-	$	616,205	X	$	308,103
177	1753	MONUMENT SUBSTATION	$	137,717	$	-	X	$	68,859
178	1553	NORTH FORK SUBSTATION	$	138,220	$	138,220	X	$	138,220
179	1615	NORTH YUMA SUBSTATION	$	1,009,680	$	1,009,680	X	$	1,009,680
180	1615	NORTH YUMA SUBSTATION	$	6,081	$	6,081	X	$	6,081
181	3717	NORTH YUMA-RED WILLOW LINE	$	28,270	$	28,270	X	$	28,270
182	3767	NORTH YUMA-WRAY LINE	$	142,616	$	142,903	X	$	142,760
183	3767	NORTH YUMA-WRAY LINE	$	-	$	162,703	X	$	81,352
184	1512	NUCLA PLANT SUBSTATION	$	139,884	$	139,884	X	$	139,884
185	2014	PEGS (ESCALANTE) SWITCHING STATION	$	214,542	$	214,542	X	$	214,542
186	2014	PEGS (ESCALANTE) SWITCHING STATION	$	-	$	38,821	X	$	19,411
187	2014	PEGS (ESCALANTE) SWITCHING STATION	$	266,544	$	-	X	$	133,272
188	3930	PEGS-GALLUP SW TAP LINE	$	8,011,529	$	8,092,806	X	$	8,052,168
189	2063	PICACHO SUBSTATION	$	132,715	$	132,715	X	$	132,715
190	2063	PICACHO SUBSTATION	$	31,130	$	31,130	X	$	31,130
191	2063	PICACHO SUBSTATION	$	-	$	47,208	X	$	23,604
192	1675	PILOT BUTTE SUBSTATION	$	10,127	$	-	X	$	5,064

193	3993	PLAZA-ZINZER LINE	$ 560,132	$ 560,132	X			$ 560,132
194	3601	PONCHA-SAN LUIS LINE	$ -	$ 17,458	X			$ 8,729
195	3601	PONCHA-SAN LUIS LINE	$ -	$ 44,878	X			$ 22,439
196	3769	RED WILLOW-WAGES LINE	$ 40,655	$ 40,655	X			$ 40,655
197	2111	REUNION SUBSTATION	$ 769,465	$ 773,000	X			$ 771,233
198	1651	RIVERTON SUBSTATION	$ 26,443	$ -	X			$ 13,222
199	1556	SAN LUIS VALLEY SUBSTATION	$ 224,703	$ -	X			$ 112,352
200	1888	SAN LUIS VALLEY SUBSTATION	$ 93,303	$ 93,303	X			$ 93,303
201	3843	SAN LUIS VALLEY-STANLEY TAP LINE	$ 43,189	$ 43,189	X			$ 43,189
202	3974	SAND CANYON-GOOD POINT LINE	$ -	$ 3,940	X			$ 1,970
203	3723	SANDHILLS-WRAY LINE	$ 172,484	$ 172,484	X			$ 172,484
204	3839	SHENANDOAH-MANCOS TAP LINE	$ -	$ 263,266	X			$ 131,633
205	1623	SIDNEY 230 KV SUBSTATION	$ -	$ 505,055		X	50%	$ 126,264
206	1623	SIDNEY 230 KV SUBSTATION	$ 643,922	$ -		X	50%	$ 160,981
207	3846	SILVERTON TAP-BURRO BRIDGE LINE	$ 3,873	$ 3,873	X			$ 3,873
208	2108	SLATER SUBSTATION	$ 1,855,029	$ 1,855,029	X			$ 1,855,029
209	2032	SOCORRO SUBSTATION	$ 634,785	$ 634,785	X			$ 634,785
210	1900	SOUTH CANAL SWITCHING STATION	$ 20,518	$ 20,518	X			$ 20,518
211	3761	SOUTH FORK-BONNEY CREEK LINE	$ 25,790	$ 25,790	X			$ 25,790
212	3709	SOUTH FORK-HELL CREEK LINE	$ 160,765	$ 161,052	X			$ 160,909
213	3645	SPRING CREEK MESA-BULLOCK LINE	$ -	$ 20,264	X			$ 10,132
214	2034	SPRINGER SUBSTATION	$ 93,375	$ 93,375	X			$ 93,375
215	2034	SPRINGER SUBSTATION	$ 693,650	$ -	X			$ 346,825
216	2034	SPRINGER SUBSTATION	$ 82,680	$ -	X			$ 41,340
217	3844	STANLEY TAP-WAVERLY LINE	$ -	$ 37,197	X			$ 18,599
218	2226	STARR NELSON SWITCHING STATION	$ -	$ 9,849	X			$ 4,925
219	1782	STEGALL AC/DC TIE	$ (8,466)	$ (9,424)	X			$ (8,945)
220	1782	STEGALL AC/DC TIE	$ 347,593	$ -	X			$ 173,797
221	1782	STEGALL AC/DC TIE	$ (7,032)	$ -	X			$ (3,516)
222	3524	STEM BEACH-WALSENBURG LINE	$ -	$ 152,894	X			$ 76,447
223	1854	STORY 230 KV SUBSTATION	$ 244,402	$ 246,239	X			$ 245,321
224	3702	STORY-NORTH YUMA LINE	$ 44,052	$ 44,052	X			$ 44,052
225	3905	TAOS-BLACK LAKE LINE	$ 244,095	$ 244,095	X			$ 244,095
226	1644	THERMOPOLIS 115KV SUBSTATION	$ 95,332	$ -	X			$ 47,666
227	2218	TORREON SUBSTATION	$ -	$ 301,635	X			$ 150,818
228	2218	TORREON SUBSTATION	$ 970,061	$ -	X			$ 485,031
229	1897	VERNON SWITCHING STATION	$ 263,526	$ 263,526	X			$ 263,526
230	3829	VERNON-VERNON TAP LINE	$ 32,459	$ 32,459	X			$ 32,459
231	3804	WAGES-WAUNETA LINE	$ 51,234	$ 51,518	X			$ 51,376
232	3859	WALSENBURG-CO/NM STATE LINE	$ 63,271	$ 63,271	X			$ 63,271
233	1524	WALSENBURG SUBSTATION	$ 291,005	$ 291,005	X			$ 291,005
234	1524	WALSENBURG SUBSTATION	$ 53,825	$ 53,825	X			$ 53,825
235	3854	WALSENBURG-LUDLOW TAP LINE	$ -	$ 3,253	X			$ 1,627
236	3520	WEST (SCPC)-STEM BEACH LINE	$ 529,329	$ 529,329	X			$ 529,329
237	3520	WEST (SCPC)-STEM BEACH LINE	$ 91,327	$ 91,394	X			$ 91,361
238	3928	WHITE SANDS TAP	$ -	$ 16,591	X			$ 8,296
239	2067	WHITNEY SWITCHING STATION	$ 820,413	$ 820,413	X			$ 820,413
240	2017	WILLARD SWITCHING STATION	$ 67,357	$ 67,357	X			$ 67,357
241	3647	WILLOW CREEK-VILAS TAP LINE	$ -	$ 21,470	X			$ 10,735
242	1617	WINDY GAP SUBSTATION	$ 1,044,440	$ 1,102,207	X			$ 1,073,324
243	1617	WINDY GAP SUBSTATION	$ 117,774	$ 117,774	X			$ 117,774
244	1617	WINDY GAP SUBSTATION	$ 265,806	$ 266,483	X			$ 266,145

245	1617	WINDY GAP SUBSTATION	$	143,549	$	-	X	$	71,775
246	1607	WRAY SUBSTATION	$	20,046	$	20,046	X	$	20,046
247	1607	WRAY SUBSTATION	$	39,387	$	39,496	X	$	39,442
248	2072	YAH-TA-HEY SUBSTATION	$	6,859	$	28,240	X	$	17,550
249	3971	YELLOW II SWITCH-YELLOW JACKET W LINE	$	-	$	6,310	X	$	3,155
250	3973	YELLOW JACKET W-MAIN SWITCH LINE	$	-	$	24,679	X	$	12,340

251 Notes:

252 A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Construction Work in Progress
Data: Year Ending December 31, 2018

A	B	C	D	E	F	G	H	I	J	K
Line	Facility Name	Allowable Recovery (Note A)	Pricing Zone (Note B)	Fac ID	Construction Start Date	In-Service Date (Estimated)	BOY Balance	EOY Balance	Average Balance (Col H & I)	Includable in Rate Base (Note C) (Col C * Col J)
1									Construction Work in Progress Total:	$ 35,117,570
2	ALAMOGORDO-TNP LINE	0.5	West	3936		unknown	$ 271	$ -	$ 136	$ 68
3	ALAMOGORDO-TNP LINE	0.5	West	3936		10/2/2017	$ 31,516	$ -	$ 15,758	$ 7,879
4	ALAMOGORDO SUBSTATION	0.5	West	2018		12/31/2016	$ 178,459	$ -	$ 89,230	$ 44,615
5	ALAMOGORDO SUBSTATION	0.5	West	2018		unknown	$ (5,590)	$ -	$ (2,795)	$ (1,398)
6	ALAMOGORDO SUBSTATION	0.5	West	2018		unknown	$ 624,881	$ -	$ 312,441	$ 156,220
7	ALTA LUNA-CABALLO LINE	0.5	West	4122		12/29/2017	$ 271	$ 3,223	$ 1,747	$ 874
8	ALTA LUNA-CABALLO LINE	0.5	West	4122		unknown	$ -	$ 31,154	$ 15,577	$ 7,789
9	ALTA LUNA-CABALLO LINE	0.5	West	4122		unknown	$ -	$ 4,410	$ 2,205	$ 1,103
10	ALTA LUNA-CABALLO LINE	0.5	West	4122		12/31/2019	$ 21,321	$ -	$ 10,661	$ 5,330
11	ALTA LUNA-MIMBRES LINE	0.5	West	4123		12/31/2016	$ -	$ 3,334	$ 1,667	$ 834
12	ANASAZI-YELLOW JACKET II LINE	0.5	West	4131		12/31/2018	$ 2,168	$ -	$ 1,084	$ 542
13	ANTON-LAST CHANCE TAP LINE	0.5	West	3833		9/30/2018	$ 14,142	$ -	$ 7,071	$ 3,536
14	AULT-STEAMBOAT TAP LINE	0.5	West	3864		9/13/2017	$ 95,186	$ 99,737	$ 97,462	$ 48,731
15	AULT SUBSTATION	0.5	West	1789		12/31/2018	$ 3,034,049	$ 3,180,954	$ 3,107,502	$ 1,553,751
16	AULT SUBSTATION	0.5	West	1789		12/31/2020	$ 25,636	$ 28,201	$ 26,919	$ 13,459
17	AULT SUBSTATION	0.5	West	1789		01/30/2015	$ 72,070	$ 76,490	$ 74,280	$ 37,140
18	AULT SUBSTATION	0.5	West	1789		10/31/2015	$ 32,782	$ 35,445	$ 34,114	$ 17,057
19	AULT SUBSTATION	0.5	West	1789		12/31/2016	$ -	$ 53,298	$ 26,649	$ 13,325
20	AULT SUBSTATION	0.5	West	1789		9/30/2016	$ -	$ 106,193	$ 53,097	$ 26,548
21	AULT SUBSTATION	0.5	West	1789		12/20/2018	$ -	$ 2,073	$ 1,037	$ 518
22	AULT SUBSTATION	0.5	West	1789		9/1/2020	$ -	$ 25,825	$ 12,913	$ 6,456
23	AXIAL BASIN-MEEKER LINE	0.5	West	3614		unknown	$ -	$ 3	$ 2	$ 1
24	AXIAL BASIN-MEEKER LINE	0.5	West	3614		12/30/2020	$ 228	$ 101,646	$ 50,937	$ 25,469
25	AXIAL BASIN-MEEKER LINE	0.5	West	3614		unknown	$ 261,157	$ -	$ 130,579	$ 65,289
26	AXIAL BASIN-MEEKER LINE	0.5	West	3614		12/31/2018	$ (511,794)	$ -	$ (255,897)	$ (127,949)
27	AXIAL BASIN SUBSTATION	0.5	West	1539		unknown	$ 255,070	$ -	$ 127,535	$ 63,768
28	AXIAL BASIN SUBSTATION	0.5	West	1539		12/31/2016	$ 2,645	$ -	$ 1,323	$ 661
29	BAYFIELD SUBSTATION	0.5	West	1528		12/31/2018	$ -	$ 184	$ 92	$ 46
30	BAYFIELD SUBSTATION	0.5	West	1528		12/31/2019	$ -	$ 20,902	$ 10,451	$ 5,226
31	BAYFIELD SUBSTATION	0.5	West	1528		unknown	$ -	$ 1,476	$ 738	$ 369
32	BEARS EARS-BONANZA LINE	0.5	West	3759		unknown	$ -	$ 26,301	$ 13,151	$ 6,575
33	BERNARDO-SOCORRO LINE	0.5	West	4135		unknown	$ 81,304	$ 618,506	$ 349,905	$ 174,953
34	BERNARDO-SOCORRO LINE	0.5	West	4135		unknown	$ -	$ 3,879	$ 1,940	$ 970
35	BERNARDO-SOCORRO LINE	0.5	West	4135		unknown	$ 2,850	$ -	$ 1,425	$ 713
36	BERNARDO-SOCORRO LINE	0.5	West	4135		7/14/2017	$ 65,830	$ -	$ 32,915	$ 16,458
37	BIG SANDY SUBSTATION	0.5	West	1608		10/30/2017	$ 271	$ -	$ 136	$ 68
38	BIG SANDY SUBSTATION	0.5	West	1608		unknown	$ 36,305	$ -	$ 18,153	$ 9,076
39	BODO-HESPERUS DBL CKT LINE	0.5	West	3641		12/31/2019	$ 80,158	$ -	$ 40,079	$ 20,040

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Construction Work in Progress
Data: Year Ending December 31, 2018

A	B	C	D	E	F	G	H	I	J	K
Line	Facility Name	Allowable Recovery (Note A)	Pricing Zone (Note B)	Fac ID	Construction Start Date	In-Service Date (Estimated)	BOY Balance	EOY Balance	Average Balance (Col H & I)	Includable in Rate Base (Note C) (Col C * Col J)
40	BOONE-LA JUNTA LINE	0.5	West	3586		12/30/2014	$ 319,524	$ -	$ 159,762	$ 79,881
41	BOONE-LAMAR LINE	0.5	West	3530		6/13/2018	$ -	$ 28,319	$ 14,160	$ 7,080
42	BOONE-LAMAR LINE	0.5	West	3530		unknown	$ 8,947	$ -	$ 4,474	$ 2,237
43	BULLOCK SUBSTATION	0.5	West	1531		10/31/2018	$ -	$ 25,577	$ 12,789	$ 6,394
44	BURLINGTON-LAMAR LINE	0.5	West	4110		unknown	$ 2,112,983	$ 2,269,801	$ 2,191,392	$ 1,095,696
45	BURLINGTON-BURLINGTON LINE	0.5	West	3764		unknown	$ 35,119	$ -	$ 17,560	$ 8,780
46	BURLINGTON-WRAY LINE	0.5	West	3988		12/21/2018	$ 22,976	$ -	$ 11,488	$ 5,744
47	BURLINGTON-WRAY LINE	0.5	West	3988		unknown	$ 8,280	$ -	$ 4,140	$ 2,070
48	BURRO BRIDGE-SUNSHINE LINE	0.5	West	3847		unknown	$ 108	$ -	$ 54	$ 27
49	CABALLO-MIMBRES LINE	0.5	West	3979		9/12/2018	$ 447	$ 10,155	$ 5,301	$ 2,651
50	CABALLO-MIMBRES LINE	0.5	West	3979		5/15/2017	$ 4,814	$ -	$ 2,407	$ 1,204
51	CAHONE SUBSTATION	0.5	West	1564		1/4/2018	$ 49,471	$ 684,126	$ 366,799	$ 183,399
52	CAHONE SUBSTATION	0.5	West	1564		10/31/2017	$ -	$ 3,810	$ 1,905	$ 953
53	CAHONE SUBSTATION	0.5	West	1564		12/31/2016	$ 271	$ -	$ 136	$ 68
54	CAHONE-EMPIRE LINE	0.5	West	3626		12/30/2017	$ -	$ 145,135	$ 72,568	$ 36,284
55	CAHONE-EMPIRE LINE	0.5	West	3626		12/31/2018	$ 209,619	$ -	$ 104,810	$ 52,405
56	CASCADE SUBSTATION	0.5	West	1540		unknown	$ -	$ 19,371	$ 9,686	$ 4,843
57	CASCADE-SILVERTON TAP LINE	0.5	West	3845		unknown	$ -	$ 738	$ 369	$ 185
58	CEMEX-DOWE FLATS LINE	0.5	West	4045		12/31/2017	$ 16,577	$ 268,925	$ 142,751	$ 71,376
59	CLAPHAM SUBSTATION	0.5	West	2021		10/31/2017	$ 271	$ -	$ 136	$ 68
60	CLAPHAM SUBSTATION	0.5	West	2021		unknown	$ 38,387	$ -	$ 19,194	$ 9,597
61	COLFER-GREENHOUSE LINE	0.5	West	4090		12/31/2017	$ 534,653	$ 253,460	$ 394,057	$ 197,028
62	COLFER-GREENHOUSE LINE	0.5	West	4090		unknown	$ (6,920)	$ 336,014	$ 164,547	$ 82,274
63	COLFER-RATTLESNAKE RIDGE LINE	0.5	West	4091		12/29/2016	$ 274,024	$ 297,653	$ 285,839	$ 142,919
64	COLFER-RATTLESNAKE RIDGE LINE	0.5	West	4091		12/29/2016	$ 253	$ 295	$ 274	$ 137
65	COMANCHE-WALSENBURG LINE	0.5	West	3806		3/30/2015	$ 122,440	$ -	$ 61,220	$ 30,610
66	CORTEZ PIPELINE TAP-MAIN SWITCH LINE	0.5	West	4054		1/2/2019	$ 1,823	$ -	$ 912	$ 456
67	CORTEZ PIPELINE TAP-TOWAOC CANAL TAP L	0.5	West	4052		1/1/2019	$ 1,852	$ -	$ 926	$ 463
68	COW CANYON-HOVENWEEP LINE	0.5	West	4139		12/31/2018	$ 2,168	$ -	$ 1,084	$ 542
69	COW CANYON-YELLOW JACKET LL LINE	0.5	West	4140		1/1/2019	$ 1,823	$ -	$ 912	$ 456
70	CRAIG SWITCHING STATION	0.5	West	1560		unknown	$ -	$ 12,161	$ 6,081	$ 3,040
71	DEERING LAKE SWITCHING STATION	0.5	West	1618		11/30/2014	$ 271	$ -	$ 136	$ 68
72	DIFFICULTY SUBSTATION	0.5	West	1647		unknown	$ 271	$ -	$ 136	$ 68
73	DIFFICULTY SUBSTATION	0.5	West	1647		unknown	$ 3,638	$ -	$ 1,819	$ 910
74	DONA ANA-ALAMOGORDO LINE	0.5	West	3921		unknown	$ 271	$ -	$ 136	$ 68
75	DONA ANA-ALAMOGORDO LINE	0.5	West	3921		6/2/2017	$ 15,925	$ -	$ 7,963	$ 3,981
76	DONA ANA SWITCHING STATION	0.5	West	2008		unknown	$ -	$ (1)	$ (1)	$ (0)
77	DURANGO SUBSTATION	0.5	West	1501		unknown	$ 271	$ -	$ 136	$ 68
78	ECKLEY SUBSTATION	0.5	West	1721		12/31/2018	$ 224	$ 235	$ 230	$ 115
79	ECKLEY SUBSTATION	0.5	West	1721		unknown	$ 214,176	$ -	$ 107,088	$ 53,544
80	ELEPHANT BUTTE-LAS CRUCES LINE	0.5	West	3920		unknown	$ -	$ 411	$ 206	$ 103

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81	ELEPHANT BUTTE-LAS CRUCES LINE	0.5	West	3920		12/31/2017	$ -	$ 2,994	$ 1,497	$ 749
82	ELEPHANT BUTTE-HOT SPRINGS TAP LINE	0.5	West	3925		unknown	$ 12,143	$ 12,724	$ 12,434	$ 6,217
83	EMIL ANDERSON-FOREST LAKES LINE	0.5	West	3861		10/31/2015	$ 586,905	$ -	$ 293,453	$ 146,726
84	EMIL ANDERSON-MONUMENT LINE	0.5	West	3863		9/1/2018	$ 147,843	$ 154,913	$ 151,378	$ 75,689
85	EMPIRE SUBSTATION	0.5	West	1503		12/31/2018	$ -	$ 16,380	$ 8,190	$ 4,095
86	EMPIRE SUBSTATION	0.5	West	1503		12/31/2019	$ 271	$ -	$ 136	$ 68
87	ERIE SUBSTATION	0.5	West	2087		10/31/2015	$ 271	$ -	$ 136	$ 68
88	FRASER (METTLER)-MILL LINE	0.5	West	3809		12/31/2017	$ 488	$ -	$ 244	$ 122
89	FRASER (METTLER)-WINDY GAP LINE	0.5	West	3708		7/14/2017	$ 45,748	$ -	$ 22,874	$ 11,437
90	FULLER SUBSTATION	0.5	West	1915		unknown	$ 271	$ -	$ 136	$ 68
91	GALLUP-YA-TA-HEY LINE	0.5	West	3916		2/14/2018	$ 1,866,831	$ -	$ 933,416	$ 466,708
92	GARNET MESA TAP-HOTCHKISS LINE	0.5	West	3853		12/31/2016	$ 269,051	$ 354,032	$ 311,542	$ 155,771
93	GARNET MESA TAP-SUBSTATION LINE	0.5	West	3660		12/1/2018	$ -	$ 1,795	$ 898	$ 449
94	GARNET MESA TAP-SUBSTATION LINE	0.5	West	3660		12/31/2018	$ -	$ 560	$ 280	$ 140
95	GLADSTONE-SPRINGER LINE	0.5	West	3982		12/30/2014	$ 23,166	$ -	$ 11,583	$ 5,792
96	GOODMAN POINT-MAIN SWITCH LINE	0.5	West	3975		1/4/2019	$ 1,938	$ -	$ 969	$ 485
97	GORE PASS-WINDY GAP LINE	0.5	West	3713		09/01/2020	$ 1,193,388	$ 1,250,452	$ 1,221,920	$ 610,960
98	GORE PASS-WINDY GAP LINE	0.5	West	3713		12/31/2018	$ 46,664	$ -	$ 23,332	$ 11,666
99	GORE PASS SUBSTATION	0.5	West	1613		12/31/2017	$ -	$ 11,962	$ 5,981	$ 2,991
100	GORE PASS SUBSTATION	0.5	West	1613		unknown	$ 271	$ -	$ 136	$ 68
101	GRANBY PUMPING PLANT-WINDY GAP LINE	0.5	West	3955		10/30/2014	$ 11,459,163	$ -	$ 5,729,582	$ 2,864,791
102	GRAND JUNCTION-MONTROSE LINE	0.5	West	3514		12/21/2017	$ 171,784	$ 200,377	$ 186,081	$ 93,040
103	GRAND JUNCTION-MONTROSE LINE	0.5	West	3514		unknown	$ 182,122	$ -	$ 91,061	$ 45,531
104	GREENHOUSE SUBSTATION	0.5	West	2204		12/31/2015	$ 2,821	$ -	$ 1,411	$ 705
105	GRESHAM-BLACK FOREST TAP LINE	0.5	West	3834		12/31/2016	$ 175,125	$ -	$ 87,563	$ 43,781
106	HAPPY CANYON SUBSTATION	0.5	West	1505		unknown	$ 1,270	$ -	$ 635	$ 318
107	HAYDEN SUB-AXIAL BASIN LINE	0.5	West	3528		unknown	$ 87,241	$ 92,698	$ 89,970	$ 44,985
108	HAYDEN SUB-AXIAL BASIN LINE	0.5	West	3528		1/22/2018	$ 541	$ 463	$ 502	$ 251
109	HAYDEN SUB-AXIAL BASIN LINE	0.5	West	3528		unknown	$ 1,235	$ 140,939	$ 71,087	$ 35,544
110	HAYDEN SUB-AXIAL BASIN LINE	0.5	West	3528		3/7/2018	$ 3,793	$ 158,863	$ 81,328	$ 40,664
111	HELL CREEK TAP-LIBERTY LINE	0.5	West	3791		6/2/2017	$ 18,480	$ -	$ 9,240	$ 4,620
112	HENRY LAKE-BROMLEY LINE	0.5	West	3949		unknown	$ -	$ (9,092)	$ (4,546)	$ (2,273)
113	HENRY LAKE-BROMLEY LINE	0.5	West	3949		unknown	$ -	$ 306	$ 153	$ 77
114	HENRY LAKE SUBSTATION	0.5	West	2041		12/31/2018	$ -	$ 162	$ 81	$ 41
115	HENRY LAKE SUBSTATION	0.5	West	2041		12/31/2018	$ -	$ (1,124,816)	$ (562,408)	$ (281,204)
116	HERNANDEZ-OJO CALIENTE TAP LINE	0.5	West	3904		09/31/2017	$ 266,779	$ 1,163	$ 133,971	$ 66,986
117	HERNANDEZ-OJO CALIENTE TAP LINE	0.5	West	3904		3/24/2017	$ 190,432	$ -	$ 95,216	$ 47,608
118	HESPERUS SUBSTATION	0.5	West	1603		12/31/2018	$ -	$ 13,276	$ 6,638	$ 3,319
119	HESPERUS SUBSTATION	0.5	West	2241		unknown	$ -	$ 984	$ 492	$ 246
120	HESPERUS SUBSTATION	0.5	West	2241		12/31/2017	$ 7,132,807	$ -	$ 3,566,404	$ 1,783,202
121	HESPERUS SUBSTATION	0.5	West	2241		unknown	$ 7,248	$ -	$ 3,624	$ 1,812

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122	HESPERUS-NM STATE LINE	0.5	West	3506		unknown	$ -	$ 307	$ 154	$ 77
123	HESPERUS-NM STATE LINE	0.5	West	3506		unknown	$ 113,585	$ -	$ 56,793	$ 28,396
124	HIDALGO-PYRAMID LINE	0.5	West	3510		10/2/2017	$ 90,360	$ -	$ 45,180	$ 22,590
125	HOLLOMAN TAP-ALAMOGORDO LINE	0.5	West	3927		6/16/2018	$ 12,953	$ -	$ 6,477	$ 3,238
126	HOTCHKISS SUBSTATION	0.5	West	1506		6/30/2020	$ -	$ 374	$ 187	$ 94
127	HOVENWEEP-SAND CANYON LINE	0.5	West	3972		1/1/2019	$ 2,198	$ -	$ 1,099	$ 550
128	JOES-ARICKAREE LINE	0.5	West	3831		4/1/2017	$ 267,228	$ -	$ 133,614	$ 66,807
129	KEOTA SUBSTATION	0.5	West	2198		unknown	$ -	$ (247,089)	$ (123,545)	$ (61,772)
130	KEOTA SUBSTATION	0.5	West	2198		unknown	$ 271	$ -	$ 136	$ 68
131	KREMMLING SUBSTATION	0.5	West	1911		4/1/2017	$ 324,051	$ -	$ 162,026	$ 81,013
132	LA JUNTA SUBSTATION	0.5	West	1507		unknown	$ 271	$ -	$ 136	$ 68
133	LAJUNTA-WILLOW CREEK LINE	0.5	West	3631		unknown	$ 625,711	$ -	$ 312,856	$ 156,428
134	LAMAR SUBSTATION	0.5	West	1550		12/31/2018	$ -	$ 1,054,146	$ 527,073	$ 263,537
135	LINCOLN SUBSTATION	0.5	West	1679		12/31/2018	$ -	$ 7,227	$ 3,614	$ 1,807
136	LINCOLN SUBSTATION	0.5	West	1679		unknown	$ 271	$ -	$ 136	$ 68
137	LONGS PEAK SUBSTATION	0.5	West	1822		4/30/2016	$ 13,714	$ 33,122	$ 23,418	$ 11,709
138	LOST CANYON SUBSTATION	0.5	West	1549		unknown	$ 271	$ -	$ 136	$ 68
139	LOST CANYON-TOWAOC CANAL TAP LINE	0.5	West	4050		12/31/2018	$ 2,795	$ -	$ 1,398	$ 699
140	LOST CREEK TAP	0.5	West	3014		unknown	$ 4,253	$ -	$ 2,127	$ 1,063
141	LOST CREEK TAP	0.5	West	3014		12/28/2018	$ 3,148	$ -	$ 1,574	$ 787
142	LOVELL-BIG GEORGE LINE	0.5	West	3742		12/31/2018	$ 341,913	$ -	$ 170,957	$ 85,478
143	MAIN SWITCH-MOQUI C LINE	0.5	West	4141		1/2/2019	$ 1,864	$ -	$ 932	$ 466
144	MAIN SWITCH-MOQUI C LINE	0.5	West	4141		unknown	$ 271	$ -	$ 136	$ 68
145	MAIN SWITCHING STATION	0.5	West	1535		unknown	$ 1,372	$ 9,631	$ 5,502	$ 2,751
146	MAIN SWITCHING STATION	0.5	West	1535		unknown	$ -	$ 77	$ 39	$ 19
147	MANCOS TAP-LOST CANYON LINE	0.5	West	3840		unknown	$ -	$ 44,216	$ 22,108	$ 11,054
148	MAVERICK-MONTROSE LINE	0.5	West	4128		unknown	$ -	$ 3,414	$ 1,707	$ 854
149	MAVERICK-NORWOOD LINE	0.5	West	4073		unknown	$ 453	$ 78,243	$ 39,348	$ 19,674
150	MAVERICK-NORWOOD LINE	0.5	West	4073		unknown	$ 271	$ -	$ 136	$ 68
151	MAVERICK-NUCLA LINE	0.5	West	4129		unknown	$ 5,544	$ 324,202	$ 164,873	$ 82,437
152	MAVERICK-NUCLA LINE	0.5	West	4129		unknown	$ 271	$ -	$ 136	$ 68
153	MCBRYDE SUBSTATION	0.5	West	2122		12/31/2019	$ -	$ 230	$ 115	$ 58
154	MEEKER SUBSTATION	0.5	West	1543		12/31/2018	$ 69,388	$ 1,918,312	$ 993,850	$ 496,925
155	MEEKER SUBSTATION	0.5	West	1543		10/31/2017	$ 11,145	$ 16,072	$ 13,609	$ 6,804
156	MEEKER SUBSTATION	0.5	West	1543		1/2/2019	$ -	$ 698	$ 349	$ 175
157	MEEKER SWITCHING STATION	0.5	West	2104		12/31/2018	$ 1,019	$ 1,247	$ 1,133	$ 567
158	MEEKER SWITCHING STATION	0.5	West	2104		3/24/2017	$ 271	$ -	$ 136	$ 68
159	MEEKER-RANGELY LINE	0.5	West	3577		unknown	$ -	$ 943	$ 472	$ 236
160	MEEKER-RIFLE LINE	0.5	West	3529		12/31/2018	$ 268,700	$ -	$ 134,350	$ 67,175
161	MEEKER-RIFLE LINE	0.5	West	3529		12/31/2018	$ 468,966	$ -	$ 234,483	$ 117,242
162	MONTROSE SUBSTATION	0.5	West	1588		6/19/2014	$ 17,072	$ -	$ 8,536	$ 4,268

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163	MONTROSE SUBSTATION	0.5	West	1547		12/30/2019	$ 272	$ 552	$ 412	$ 206
164	MONTROSE SUBSTATION	0.5	West	1547		12/31/2018	$ -	$ 239,905	$ 119,953	$ 59,976
165	MONTROSE-HAPPY CANYON LINE	0.5	West	3515		12/31/2018	$ 10,448	$ -	$ 5,224	$ 2,612
166	MONTROSE-HESPERUS LINE	0.5	West	3611		12/31/2017	$ 51,179	$ 160,835	$ 106,007	$ 53,004
167	MONTROSE-NUCLA LINE	0.5	West	3519		12/1/2019	$ 19,219,480	$ 28,507,128	$ 23,863,304	$ 11,931,652
168	MONTROSE-NUCLA LINE	0.5	West	3519		12/19/2017	$ 108,698	$ 239,600	$ 174,149	$ 87,075
169	MONUMENT SUBSTATION	0.5	West	1753		unknown	$ 271	$ -	$ 136	$ 68
170	MONUMENT SUBSTATION	0.5	West	1753		unknown	$ 68,478	$ -	$ 34,239	$ 17,120
171	NERES CANAL-RATTLESNAKE RIDGE LINE	0.5	West	4092		unknown	$ 82,804	$ 94,630	$ 88,717	$ 44,359
172	NERES CANAL-SOUTH KERSEY LINE	0.5	West	4094		unknown	$ 147,956	$ 167,060	$ 157,508	$ 78,754
173	NERES CANAL-SOUTH KERSEY LINE	0.5	West	4094		unknown	$ -	$ 74	$ 37	$ 19
174	NORTH FORK SUBSTATION	0.5	West	1553		unknown	$ 271	$ -	$ 136	$ 68
175	NORTH FORK SUBSTATION	0.5	West	1553		unknown	$ 9,956	$ -	$ 4,978	$ 2,489
176	NORTH YUMA SUBSTATION	0.5	West	1615		unknown	$ 301	$ -	$ 151	$ 75
177	NORTH YUMA-WRAY LINE	0.5	West	3767		4/1/2015	$ 161,380	$ -	$ 80,690	$ 40,345
178	NUCLA PLANT SUBSTATION	0.5	West	1512		unknown	$ 301	$ -	$ 151	$ 75
179	NUCLA-CAHONE LINE	0.5	West	3625		12/31/2021	$ 7,933,157	$ 18,186,509	$ 13,059,833	$ 6,529,917
180	NUCLA-CAHONE LINE	0.5	West	3625		12/31/2018	$ 13,090	$ -	$ 6,545	$ 3,273
181	NUCLA-SUNSHINE LINE	0.5	West	3822		unknown	$ -	$ 9,494	$ 4,747	$ 2,374
182	OJO-TAOS LINE	0.5	West	3929		unknown	$ 140,623	$ 192,279	$ 166,451	$ 83,226
183	OJO-TAOS LINE	0.5	West	3929		unknown	$ -	$ 6,382	$ 3,191	$ 1,596
184	OJO-TAOS LINE	0.5	West	3929		12/31/2017	$ -	$ 396,706	$ 198,353	$ 99,177
185	PEGS (ESCALANTE) SWITCHING STATION	0.5	West	2014		5/8/2018	$ -	$ 60,048	$ 30,024	$ 15,012
186	PEGS-GALLUP SW TAP LINE	0.5	West	3930		unknown	$ 5,738	$ 8,458	$ 7,098	$ 3,549
187	PEGS-GALLUP SW TAP LINE	0.5	West	3930		12/31/2017	$ 46,268	$ 146,067	$ 96,168	$ 48,084
188	PEGS-GALLUP SW TAP LINE	0.5	West	3930		unknown	$ 35,746	$ 93,601	$ 64,674	$ 32,337
189	PEGS-GALLUP SW TAP LINE	0.5	West	3930		11/15/2017	$ 80,603	$ 223,949	$ 152,276	$ 76,138
190	PEGS-GALLUP SW TAP LINE	0.5	West	3930		unknown	$ -	$ 73,224	$ 36,612	$ 18,306
191	PONCHA-SAN LUIS LINE	0.5	West	3601		6/30/2017	$ -	$ 92,938	$ 46,469	$ 23,235
192	PONCHA-SAN LUIS LINE	0.5	West	3601		12/21/2018	$ 17,225	$ -	$ 8,613	$ 4,306
193	PONY CREEK-KEOTA LINE	0.5	West	4098		9/30/2016	$ 4,767	$ 4,767	$ 4,767	$ 2,384
194	PYRAMID SWITCHING STATION	0.5	West	2040		unknown	$ 17,396	$ 17,396	$ 17,396	$ 8,698
195	RED WILLOW-WAGES LINE	0.5	West	3769		unknown	$ -	$ 5,715	$ 2,858	$ 1,429
196	REDBOX SUBSTATION	0.5	West	2202		unknown	$ (1,323)	$ (1,323)	$ (1,323)	$ (662)
197	RIFLE 230 KV SUBSTATION	0.5	West	1516		11/30/2017	$ 340,177	$ -	$ 170,089	$ 85,044
198	RIVERTON SUBSTATION	0.5	West	1651		12/31/2018	$ -	$ 3,262	$ 1,631	$ 816
199	SAN LUIS VALLEY-WALSENBERG LINE	0.5	West	3978		unknown	$ 5,833,254	$ 6,155,658	$ 5,994,456	$ 2,997,228
200	SAND CANYON-GOOD POINT LINE	0.5	West	3974		1/3/2019	$ 2,133	$ -	$ 1,067	$ 533
201	SHENANDOAH-MANCOS TAP LINE	0.5	West	3839		8/15/2015	$ 221,681	$ -	$ 110,841	$ 55,420
202	SIDNEY 230KV SUBSTATION	0.5	Split 50/50	1623		unknown	$ -	$ 1,638	$ 819	$ 409
203	SIDNEY 230KV SUBSTATION	0.5	Split 50/50	1623		12/31/2018	$ -	$ 409,787	$ 204,894	$ 102,447

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204	SIDNEY 230KV SUBSTATION	0.5	Split 50/50	1623		unknown	$ 222,362	$ -	$ 111,181	$ 55,590
205	SIDNEY 230KV SUBSTATION	0.5	West	3846		unknown	$ -	$ 9,139	$ 4,570	$ 2,285
206	SILVERTON TAP-BURRO BRIDGE LINE	0.5	West	3645		12/31/2018	$ 2,860	$ 102,165	$ 52,513	$ 26,256
207	SPRING CREEK MESA-BULLOCK LINE	0.5	West	3645		unknown	$ 19,745	$ -	$ 9,873	$ 4,936
208	STANLEY TAP-WAVERLY LINE	0.5	West	3844		unknown	$ 271	$ -	$ 136	$ 68
209	STANLEY TAP-WAVERLY LINE	0.5	West	3844		10/31/2017	$ 3,859	$ -	$ 1,930	$ 965
210	STARR NELSON SWITCHING STATION	0.5	West	2226		unknown	$ 3,555	$ -	$ 1,778	$ 889
211	STEGALL 230 KV SUBSTATION	0.5	Split 50/50	2051		12/31/2018	$ -	$ 252	$ 126	$ 63
212	STEGALL 230 KV SUBSTATION	0.5	West	2051		12/30/2018	$ -	$ 322	$ 161	$ 81
213	STEGALL 230 KV SUBSTATION	0.5	Split 50/50	2051		unknown	$ 64,776	$ -	$ 32,388	$ 16,194
214	STEGALL AC/DC TIE	0.5	West	1782		unknown	$ 1,767	$ -	$ 884	$ 442
215	STEM BEACH SUBSTATION	0.5	West	1521		12/31/2016	$ 1,510	$ -	$ 755	$ 378
216	STEM BEACH-WALSENBURG LINE	0.5	West	3524		12/31/2018	$ 151,647	$ -	$ 75,824	$ 37,912
217	STORY 230 KV SUBSTATION	0.5	West	1854		1/1/2019	$ 7,875	$ 218,915	$ 113,395	$ 56,698
218	STORY 230 KV SUBSTATION	0.5	West	1854		12/31/2017	$ 271	$ -	$ 136	$ 68
219	STORY 230 KV SUBSTATION	0.5	West	1783		6/2/2017	$ 2,790	$ -	$ 1,395	$ 698
220	STORY 230 KV SUBSTATION	0.5	West	1783		3/30/2015	$ 18,942	$ -	$ 9,471	$ 4,736
221	TORREON SUBSTATION	0.5	West	2218		12/31/2017	$ 430,784	$ -	$ 215,392	$ 107,696
222	TORREON SUBSTATION	0.5	West	2218		unknown	$ 1,833	$ -	$ 917	$ 458
223	VERNON TAP-IDALIA LINE	0.5	West	3760		unknown	$ -	$ 6,160	$ 3,080	$ 1,540
224	WALSENBURG SUBSTATION	0.5	West	1524		9/30/2015	$ 1,331	$ 3,081	$ 2,206	$ 1,103
225	WALSENBURG SUBSTATION	0.5	West	1524		4/30/2015	$ 9,317	$ -	$ 4,659	$ 2,329
226	WALSENBURG SUBSTATION	0.5	West	1524		12/21/2017	$ 271	$ -	$ 136	$ 68
227	WALSENBURG-LUDLOW TAP LINE	0.5	West	3854		4/30/2013	$ 2,782	$ -	$ 1,391	$ 696
228	WAUNETA SUBSTATION	0.5	West	1620		unknown	$ 5,939	$ 287,537	$ 146,738	$ 73,369
229	WAUNETA SUBSTATION	0.5	West	1620		12/31/2019	$ -	$ 4,230	$ 2,115	$ 1,058
230	WELD-WHITNEY LINE	0.5	West	3990		10/15/2018	$ 108,391	$ 205,824	$ 157,108	$ 78,554
231	WEST (SCPC)-STEM BEACH LINE	0.5	West	3520		12/31/2018	$ 22,394	$ -	$ 11,197	$ 5,599
232	WHITE SANDS TAP	0.5	West	3928		unknown	$ 271	$ -	$ 136	$ 68
233	WHITE SANDS TAP	0.5	West	3928		12/28/2018	$ 1,292	$ -	$ 646	$ 323
234	WHITNEY-WINDSOR TAP LINE	0.5	West	3989		unknown	$ 59,297	$ 146,989	$ 103,143	$ 51,572
235	WILLOW CREEK SUBSTATION	0.5	West	1508		unknown	$ 271	$ -	$ 136	$ 68
236	WILLOW CREEK-VILAS TAP LINE	0.5	West	3647		12/31/2018	$ 19,563	$ -	$ 9,782	$ 4,891
237	WILLOW CREEK-VILAS TAP LINE	0.5	West	3647		unknown	$ 1,597	$ -	$ 799	$ 399
238	WINDY GAP SUBSTATION	0.5	West	1617		unknown	$ 125	$ -	$ 63	$ 31
239	YELLOW II SWITCHING STATION	0.5	West	2118		12/31/2019	$ 2,443	$ 12,055	$ 7,249	$ 3,625
240	YELLOW II SWITCH-YELLOW JACKET W LINE	0.5	West	3971		12/31/2018	$ 3,071	$ -	$ 1,536	$ 768
241	YELLOW JACKET W-MAIN SWITCH LINE	0.5	West	3973		1/2/2019	$ 3,983	$ -	$ 1,992	$ 996

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Construction Work in Progress
Data: Year Ending December 31, 2018

A	B	C	D	E	F	G	H	I	J	K
Line	Facility Name	Allowable Recovery (Note A)	Pricing Zone (Note B)	Fac ID	Construction Start Date	In-Service Date (Estimated)	BOY Balance	EOY Balance	Average Balance (Col H & I)	Includable in Rate Base (Note C) (Col C * Col J)
242	Notes:									
243	A.) Percentage recovery cannot be added or changed absent approval from FERC.									
244	B.) CWIP amounts should be directly assigned to pricing zones in Column E.									
245	C.) AFUDC ceases when CWIP is recovered in rate base. No CWIP will be included in rate base absent FERC authorization. Accounting procedures must be provided during the annual update to ensure that there is no duplicate recovery of CWIP and corresponding AFUDC capitalized.									
246	D.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.									

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Regulatory and Commission Expenses

Data: Year Ending December 31, 2018

A	B	C	D		E		F		G	
Line	Account 928	Description	Total Company		East Expenses		West Expenses		Other Expenses	
1	928.00	OUTSIDE CONSULTANTS	$	301,055	$	259,795	$	-	$	41,260
2	928.00	LABOR	$	35,709	$	27,959	$	-	$	7,749
3	928.00	OTHER	$	264,784	$	-	$	57,964	$	206,820
4		Total	$	601,548	$	287,755	$	57,964	$	255,829

5 Notes:

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Tri-State Generation and Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE
Retirement Work in Progress
Data: Year Ending December 31, 2018

A	B	C	D	E	F	G	H	I	J
Line	Fac ID	Facility	BOY Balance	EOY Balance	Average Balance	100% West	0% West	West Portion if Less than 100%	Amount
1								Retirement Work in Progress Total:	$ 1,288,839
2	3936	ALAMOGORDO-TNP LINE	$ 608	$ 608	$ 608	X			$ 608
3	3907	ALGODONES-SAN YSIDRO LINE	$ -	$ 33,755	$ 16,878	X			$ 16,878
4	3614	AXIAL BASIN-MEEKER LINE	$ 124,959	$ 144,445	$ 134,702	X			$ 134,702
5	3614	AXIAL BASIN-MEEKER LINE	$ -	$ 13,163	$ 6,582	X			$ 6,582
6	3715	BIG SANDY-LANDSMAN CREEK LINE	$ -	$ 29,550	$ 14,775	X			$ 14,775
7	3641	BODO-HESPERUS DBL CKT LINE	$ 27,713	$ 27,713	$ 27,713	X			$ 27,713
8	3586	BOONE-LA JUNTA LINE	$ 109,164	$ 109,164	$ 109,164	X			$ 109,164
9	3764	BURLINGTON-BURLINGTON LINE	$ 12,218	$ 12,218	$ 12,218	X			$ 12,218
10	3626	CAHONE-EMPIRE LINE	$ 130,944	$ 130,944	$ 130,944	X			$ 130,944
11	3626	CAHONE-EMPIRE LINE	$ -	$ 144,547	$ 72,274	X			$ 72,274
12	3921	DONA ANA-ALAMOGORDO LINE	$ 9,324	$ 14,370	$ 11,847	X			$ 11,847
13	3809	FRASER (METTLER)-MILL LINE	$ (277,398)	$ 486	$ (138,456)	X			$ (138,456)
14	3809	FRASER (METTLER)-MILL LINE	$ 17,409	$ -	$ 8,705	X			$ 8,705
15	3708	FRASER (METTLER)-WINDY GAP LINE	$ 737	$ 737	$ 737	X			$ 737
16	3853	GARNET MESA TAP-HOTCHKISS LINE	$ 1,614	$ 1,614	$ 1,614	X			$ 1,614
17	3660	GARNET MESA TAP-SUBSTATION LINE	$ -	$ 3,210	$ 1,605	X			$ 1,605
18	3713	GORE PASS-WINDY GAP LINE	$ 7,298	$ 7,298	$ 7,298	X			$ 7,298
19	3528	HAYDEN SUB-AXIAL BASIN LINE	$ -	$ 25,886	$ 12,943	X			$ 12,943
20	3791	HELL CREEK TAP-LIBERTY LINE	$ 5,189	$ 5,189	$ 5,189	X			$ 5,189
21	3904	HERNANDEZ-OJO CALIENTE TAP LINE	$ 43,837	$ 43,837	$ 43,837	X			$ 43,837
22	3506	HESPERUS-NM STATE LINE	$ 71,922	$ 71,922	$ 71,922	X			$ 71,922
23	3510	HIDALGO-PYRAMID LINE	$ 8,496	$ 8,496	$ 8,496	X			$ 8,496
24	3831	JOES-ARICKAREE LINE	$ 86,033	$ 86,033	$ 86,033	X			$ 86,033
25	3631	LAJUNTA-WILLOW CREEK LINE	$ 134,121	$ 134,190	$ 134,156	X			$ 134,156
26	3529	MEEKER-RIFLE LINE	$ 58,364	$ 58,364	$ 58,364	X			$ 58,364
27	3529	MEEKER-RIFLE LINE	$ 122,012	$ 121,905	$ 121,959	X			$ 121,959
28	3529	MEEKER-RIFLE LINE	$ -	$ 27,060	$ 13,530	X			$ 13,530

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Retirement Work in Progress
Data: Year Ending December 31, 2018

A	B	C	D	E	F	G	H	I	J
Line	Fac ID	Facility	BOY Balance	EOY Balance	Average Balance	100% West	0% West	West Portion if Less than 100%	Amount
29	3515	MONTROSE-HAPPY CANYON LINE	$ 4,762	$ 4,762	$ 4,762	X			$ 4,762
30	3767	NORTH YUMA-WRAY LINE	$ 28,566	$ 28,566	$ 28,566	X			$ 28,566
31	3601	PONCHA-SAN LUIS LINE	$ -	$ 15,912	$ 7,956	X			$ 7,956
32	3839	SHENANDOAH-MANCOS TAP LINE	$ 148,375	$ 148,375	$ 148,375	X			$ 148,375
33	1900	SOUTH CANAL SWITCHING STATION	$ -	$ (114,552)	$ (57,276)	X			$ (57,276)
34	3761	SOUTH FORK-BONNEY CREEK LINE	$ -	$ 30,493	$ 15,247	X			$ 15,247
35	3645	SPRING CREEK MESA-BULLOCK LINE	$ 3,137	$ 3,137	$ 3,137	X			$ 3,137
36	3844	STANLEY TAP-WAVERLY LINE	$ -	$ 11,909	$ 5,955	X			$ 5,955
37	3524	STEM BEACH-WALSENBURG LINE	$ 51,526	$ 51,526	$ 51,526	X			$ 51,526
38	3702	STORY-NORTH YUMA LINE	$ -	$ 205,073	$ 102,537	X			$ 102,537
39	3647	WILLOW CREEK-VILAS TAP LINE	$ 2,421	$ 2,421	$ 2,421	X			$ 2,421

40 Notes:

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Worksheet U

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Eligible Transmission Substations
Data: Year Ending December 31, 2018

				Total Company Amount				Amount included in Tri-State's ATRR				
A	B	C	D	E	F	G	H	I	J	K	L	M
Line	Account Number	Description of Asset	Type of Asset	BOY Gross Plant Cost	BOY Accumulated Depreciation	EOY Gross Plant Cost	EOY Accumulated Depreciation	BOY Gross Plant Cost	BOY Accumulated Depreciation	EOY Gross Plant Cost	EOY Accumulated Depreciation	Comments
1	350	LAND AND LAND RIGHTS	TRANSMISSION SUBSTATION	$ 7,720,301	$ 116,818	$ 8,180,941	$ 213,777	$ 5,176,579	$ 108,730	$ 5,286,743	$ 155,311	
2	352	STRUCTURES AND IMPROVEMENTS	TRANSMISSION SUBSTATION	$ 44,188,692	$ 11,463,276	$ 52,371,901	$ 12,913,649	$ 27,358,931	$ 7,889,423	$ 32,368,393	$ 8,776,422	
3	353	STATION EQUIPMENT	TRANSMISSION SUBSTATION	$ 523,543,280	$ 214,737,155	$ 556,010,771	$ 219,493,335	$ 315,605,490	$ 140,195,701	$ 334,127,210	$ 142,260,647	
4	354	TOWER AND FIXTURES	TRANSMISSION SUBSTATION	$ 801,096	$ 330,882	$ 801,096	$ 340,861	$ 447,780	$ 214,004	$ 447,780	$ 218,470	
5	355	POLES AND FIXTURES	TRANSMISSION SUBSTATION	$ 248,202	$ 119,576	$ 248,202	$ 125,169	$ 96,855	$ 56,015	$ 96,855	$ 58,279	
6	356	OVERHEAD CONDUCTORS AND DEVICES	TRANSMISSION SUBSTATION	$ 1,531,279	$ 375,421	$ 1,543,964	$ 407,074	$ 1,133,897	$ 288,631	$ 1,143,367	$ 312,096	
7	357	UNDERGROUND CONDUIT	TRANSMISSION SUBSTATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
8	358	UNDERGROUND CONDUCTOR AND DEVICES	TRANSMISSION SUBSTATION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
9	359	ROADS AND TRAILS	TRANSMISSION SUBSTATION	$ 247,127	$ 35,335	$ 348,319	$ 38,997	$ 194,432	$ 33,867	$ 294,700	$ 36,875	
10	**Totals**			**$ 578,279,978**	**$ 227,178,463**	**$ 619,505,195**	**$ 233,532,861**	**$ 350,013,964**	**$ 148,786,372**	**$ 373,765,047**	**$ 151,818,100**	

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Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Eligible Transmission Lines
Data: Year Ending December 31, 2018

				Total Company Amount				Amount included in Tri-State's ATRR				
A	B	C	D	E	F	G	H	I	J	K	L	M
Line	Account Number	Description of Asset	Type of Asset	BOY Gross Plant Cost	BOY Accumulated Depreciation	EOY Gross Plant Cost	EOY Accumulated Depreciation	BOY Gross Plant Cost	BOY Accumulated Depreciation	EOY Gross Plant Cost	EOY Accumulated Depreciation	Comments
1	350	LAND AND LAND RIGHTS	TRANSMISSION LINE	$ 119,901,869	$ 8,244,703	$ 122,822,161	$ 10,579,102	$ 95,182,961	$ 3,430,528	$ 97,616,644	$ 5,032,984	
2	352	STRUCTURES AND IMPROVEMENTS	TRANSMISSION LINE	$ 54,620	$ 36,617	$ 54,620	$ 37,684	$ -	$ -	$ -	$ -	
3	353	STATION EQUIPMENT	TRANSMISSION LINE	$ 1,448,278	$ 581,434	$ 2,749,597	$ 688,972	$ 173,892	$ 27,931	$ 2,054,810	$ 293,373	
4	354	TOWER AND FIXTURES	TRANSMISSION LINE	$ 93,241,010	$ 54,288,976	$ 93,241,010	$ 55,525,674	$ 84,184,861	$ 52,181,236	$ 84,184,861	$ 53,276,614	
5	355	POLES AND FIXTURES	TRANSMISSION LINE	$ 177,027,764	$ 95,711,696	$ 177,027,764	$ 99,039,972	$ 143,287,701	$ 71,051,011	$ 143,287,701	$ 73,864,360	
6	356	OVERHEAD CONDUCTORS AND DEVICES	TRANSMISSION LINE	$ 226,248,558	$ 106,304,630	$ 226,336,529	$ 110,220,183	$ 202,403,220	$ 90,722,599	$ 202,491,191	$ 94,303,630	
7	357	UNDERGROUND CONDUIT	TRANSMISSION LINE	$ 9,634,122	$ 1,383,426	$ 9,634,122	$ 1,543,352	$ 9,634,122	$ 1,383,426	$ 9,634,122	$ 1,543,352	
8	358	UNDERGROUND CONDUCTOR AND DEVICES	TRANSMISSION LINE	$ 5,750,709	$ 810,094	$ 5,750,709	$ 930,284	$ 5,750,709	$ 810,094	$ 5,750,709	$ 930,284	
9	359	ROADS AND TRAILS	TRANSMISSION LINE	$ 9,323,845	$ 4,207,405	$ 9,323,845	$ 4,314,605	$ 8,713,443	$ 3,753,841	$ 8,713,443	$ 3,858,244	
10	**Totals**			**$ 642,630,775**	**$ 271,568,981**	**$ 646,940,357**	**$ 282,879,827**	**$ 549,330,908**	**$ 223,360,667**	**$ 553,733,481**	**$ 233,102,841**	

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Summary of differences between SPP Formula Rate Template and West Formula Rate Template

Description	Tab Name Reference	Change/Modification
Rates Tab Addition	Rates	Rate tab sets forth: a) Point-to-Point, Schedule 1, and Schedule 2 rates $/kW; and b) FERC Annual Fee.
Other Electric Revenue - Administrative Fee -TSR Allocator	Summary	West Rate=Direct Allocator; SPP Rate=T-Tran Plant Allocator
GFA Revenue Credit Addition	Summary, OthRev Input	**Summary**: GFA revenue credit added with Direct 100 allocator **OthRev Input**: Addition of "Other Electric Revenue - GFAs" line 27
SPP Upgrades Tab	Summary, SPP Upgrades (SPP Rate)	**Summary**: Removed SPP Upgrades line item **SPP Upgrades (SPP Rate)**: Deleted SPP Upgrades tab
Network Credits	Rate Base, Expenses, Network Credits	**Rate Base**: added line 62 to reduce Rate Base by Account 252 (less interest expense) **Expenses**: added line 37 to include Account 252 interest expense **Network Credits**: added tab to capture Network Credits booked to Account 252
Account 350 (Land Rights)	Rate Base	Account 350 allocator in West Rate=T-Tran Lines; SPP Rate= T-Tran Stations
Account 565 (Transmission of Electricity by others)	Expenses	Account 565, allocator in West Rate=Direct Zero; SPP Rate = Direct
Return on Equity (ROE)	Return	Total Margins and Equities (ROE); West Rate = 9.3%; SPP FRT=9.8%. Removed 50 basis points adder for being in an RTO
Notes Payable	Return	Include debt related to “Notes Payable” in the capital structure
Formula Corrections	Inputs, CWIP	**Inputs**: West Rate Cell F79=(D79+E79)/2; SPP Rate Cell F79=E79 **CWIP**: West Rate, Column J =AVERAGE(I12:J12); SPP Rate, Column J =AVERAGE(I12:J12)/2
Account 456 (Additional Revenue Credits)	Summary, OthRev Input	**Summary**: Revised line 6 description to include Other Revenue booked to Accounts 45600. **OthRev Inputs**: Modified formula in cells D36 and F36, "Revenues from Transmission of Electricity of Others - ST Firm and Non Firm", to include Account 456 revenue credits
General Modifications	Multiple	Removed references to "SPP", "Zone 17", and other SPP specific references; modified formulas to capture West allocation; added total summary to Compl Not Class, CWIP and RWIP tabs.

Tri-State's Eligible Facilities List

Substations

Facility Name	Substation that includes Eligible Facilities	Non-Radial Facility	Radial Facility Serving Two or More Non-Affiliated Eligible Customers
ALAMOGORDO SUBSTATION		X	
ALGODONES SWITCHING STATION		X	
ALVIN SUBSTATION	X		
ANASAZI SUBSTATION	X		
ANTON SUBSTATION	X		
ARCHER SUBSTATION		X	
ARICKAREE SUBSTATION	X		
AULT SUBSTATION		X	
AXIAL BASIN SUBSTATION		X	
BARR LAKE SUBSTATION	X		
BASIN SUBSTATION		X	
BAYFIELD SUBSTATION		X	
BEAVER CREEK SUBSTATION		X	
BERNARDO SUBSTATION	X		
BETHEL SUBSTATION	X		
BIG SANDY SUBSTATION		X	
BLACK HOLLOW SUBSTATION	X		
BLACK LAKE SUBSTATION	X		
BLACK SQUIRREL SUBSTATION		X	
BLAZER SUBSTATION	X		
BLUE DOOR SUBSTATION	X		
BLUE MESA SUBSTATION		X	
BLUE RIVER SUBSTATION		X	
BLUEWATER SUBSTATION		X	
BODO SUBSTATION	X		
BOONE SUBSTATION		X	
BOYD SUBSTATION		X	
BROMLEY SUBSTATION	X		
BULLOCK SUBSTATION		X	
BURLINGTON SUBSTATION		X	
BURRO BRIDGE SUBSTATION		X	
BURRO CANYON SUBSTATION		X	
CABALLO SUBSTATION	X		
CAHONE SUBSTATION		X	
CAREY SUBSTATION	X		
CARMEL SUBSTATION	X		
CARRIZO CANYON SUBSTATION	X		
CASCADE SUBSTATION		X	
CEMEX SUBSTATION			X
CINIZA SUBSTATION		X	
CLAPHAM SUBSTATION		X	
COMANCHE SUBSTATION		X	
CORTEZ SUBSTATION	X		
COW CREEK SWITCHING STATION		X	
CRAIG SWITCHING STATION		X	
DACONO SUBSTATION	X		
DALTON SUBSTATION	X		
DAVE JOHNSTON SUBSTATION		X	
DAVIS 115KV SUBSTATION	X		
DEERING LAKE SWITCHING STATION		X	
DEL CAMINO SWITCHING STATION		X	
DIFFICULTY SUBSTATION	X		
DONA ANA SWITCHING STATION		X	
DOUGHSPOON SUBSTATION		X	
DURANGO SUBSTATION		X	
E. CORTEZ SUBSTATION	X		
ECKLEY SUBSTATION		X	
EMIGRANT SWITCHING STATION	X		
EMIL ANDERSON SUBSTATION	X		
EMPIRE SUBSTATION		X	
ERIE SUBSTATION		X	
ESPANOLA/HERNANDEZ SUBSTATION	X		
FALCON SUBSTATION	X		
FOREST LAKES SUBSTATION	X		
FRASER (METTLER) SUBSTATION	X		
FRONTIER SUBSTATION	X		
FULLER SUBSTATION		X	
GALIEN SUBSTATION	X		
GALLUP SUBSTATION	X		
GARNET MESA SUBSTATION	X		
GARY SUBSTATION	X		
GEESEN SUBSTATION		X	
GLADSTONE SUBSTATION		X	
GORE PASS SUBSTATION		X	
GRAND JUNCTION SUBSTATION		X	
GRANTS SWITCHING STATION		X	
GREENHOUSE SUBSTATION		X	
GRESHAM SUBSTATION	X		
GUNNISON VALLEY SUBSTATION	X		
HAPPY CANYON SUBSTATION		X	
HARRIS BRIDGE SUBSTATION	X		
HAYDEN SUBSTATION		X	
HENRY LAKE SUBSTATION		X	
HESPERUS SUBSTATION		X	
HORSETOOTH SUBSTATION		X	
HOTCHKISS SUBSTATION		X	

IDALIA SUBSTATION	X		
JACINTO SUBSTATION	X		
JAMES L. GREEN SUBSTATION	X		
JM SHAFER SUBSTATION		X	
JOES 115 KV SUBSTATION	X		
JUANITA SUBSTATION		X	
KEOTA SUBSTATION		X	
KREMMLING SUBSTATION		X	
LA JUNTA SUBSTATION		X	
LAMAR SUBSTATION		X	
LANDSMAN CREEK SWITCHING STATION		X	
LAPORTE SUBSTATION	X		
LARAMIE RIVER SUBSTATION		X	
LAST CHANCE SUBSTATION		X	
LIBERTY SUBSTATION		X	
LINCOLN SUBSTATION		X	
LONGMEADOW SUBSTATION	X		
LONGS PEAK SUBSTATION		X	
LORSON RANCH SUBSTATION	X		
LOST CANYON SUBSTATION		X	
LOVELL SUBSTATION		X	
LYMAN SUBSTATION		X	
LYONS SWITCHING STATION			X
MAIN SWITCHING STATION		X	
MC GREW SUBSTATION	X		
MEEKER SUBSTATION		X	
MEEKER SWITCHING STATION		X	
MIDWAY SUBSTATION		X	
MILL 115KV SUBSTATION	X		
MONTROSE SUBSTATION		X	
MONUMENT SUBSTATION		X	
MORIARTY SUBSTATION	X		
NORTH FORK SUBSTATION		X	
NORTH MESA SUBSTATION	X		
NORTH YUMA SUBSTATION		X	
NORWOOD SUBSTATION		X	
NUCLA PLANT SUBSTATION		X	
OASIS SWITCHING STATION	X		
OJO SWITCHING STATION		X	
OWL CREEK SUBSTATION	X		
PARKWAY SUBSTATION	X		
PEACH VALLEY SWITCHING STATION		X	
PEGS (ESCALANTE) SWITCHING STATION		X	
PICACHO SUBSTATION		X	
PILOT BUTTE SUBSTATION		X	
PLATTE SUBSTATION		X	
PLAZA SUBSTATION		X	
POLE CREEK SWITCHING STATION	X		
POUDRE SUBSTATION	X		
PYRAMID SWITCHING STATION		X	
RANCHO SUBSTATION	X		
RED WILLOW SUBSTATION	X		
REDBOX SUBSTATION		X	
REUNION SUBSTATION		X	
RIFLE SUBSTATION		X	
RINN VALLEY SUBSTATION	X		
RIVERTON SUBSTATION		X	
ROCKPORT SUBSTATION	X		
ROUND TOP SWITCHING STATION	X		
SAN JUAN SUBSTATION		X	
SAN LUIS VALLEY SUBSTATION		X	
SHIPROCK SUBSTATION		X	
SIDNEY 230 KV SUBSTATION		X	
SIDNEY 345 KV SUBSTATION		X	
SILVERTON SWITCHING STATION	X		
SIPRES SUBSTATION	X		
SLATER SUBSTATION		X	
SOCORRO SUBSTATION		X	
SOUTH CANAL SWITCHING STATION		X	
SOUTH FORK SUBSTATION		X	
SPRING CANYON SWITCHING STATION		X	
SPRINGER SUBSTATION		X	
STARR NELSON SWITCHING STATION		X	
STEAMBOAT SPRINGS SUBSTATION		X	
STEGALL 230KV SUBSTATION		X	
STEGALL 345 KV SUBSTATION		X	
STEGALL AC/DC TIE		X	
STEM BEACH SUBSTATION		X	
STORRIE LAKE SUBSTATION	X		
STORY SUBSTATION		X	
SUNSHINE SUBSTATION	X		
TAOS SUBSTATION		X	
TAYLOR SUBSTATION	X		
THERMOPOLIS SUBSTATION		X	
TIMNATH SWITCHING STATION		X	
TORREON SUBSTATION		X	
VERNON SUBSTATION	X		
VERNON SWITCHING STATION		X	
VILAS SUBSTATION			X
WAGES SUBSTATION	X		
WAGON WHEEL SUBSTATION	X		
WALSENBURG SUBSTATION		X	
WAUNETA SUBSTATION	X		
WEST SUBSTATION		X	
WHITNEY SWITCHING STATION		X	

WILLARD SWITCHING STATION		X	
WILLOBY SUBSTATION		X	
WILLOW CREEK SUBSTATION		X	
WILSON MESA SUBSTATION	X		
WINDY GAP SUBSTATION		X	
WOLCOTT SUBSTATION		X	
WRAY SUBSTATION		X	
YAH-TA-HEY SUBSTATION		X	
YELLOW II SWITCHING STATION		X	
ZINZER SUBSTATION	X		

Tri-State's Eligible Facilities List

Transmission Lines

Facility Name	Partial Non-Radial Facility	Non-Radial Facility	Radial Facility Serving Two or More Non-Affiliated Eligible Customers
ALAMOGORDO-HOLLYWOOD LINE		X	
ALAMOGORDO-TNP LINE		X	
ALGODONES-SAN YSIDRO LINE		X	
ALTA LUNA TAP		X	
ALVIN-SANDHILLS LINE		X	
ALVIN-WAUNETA LINE		X	
AMES HYDRO-SUNSHINE LINE		X	
ANASAZI-DOE CANYON LINE		X	
ANASAZI-YELLOW JACKET II LINE		X	
ANTON-LAST CHANCE TAP LINE		X	
ARICKAREE-ANTON LINE		X	
ARNOLD-SIPRES LINE		X	
AULT-STEAMBOAT TAP LINE		X	
AXIAL BASIN-MEEKER LINE		X	
BADWATER-SAWMILL CREEK LINE		X	
BEARS EARS-BONANZA LINE		X	
BEAVER CREEK-HOYT LINE		X	
BEAVER CRK -BEAVER CRK LINE		X	
BELEN-BERNARDO LINE		X	
BERNARDO-SOCORRO LINE		X	
BETHEL-VERNON LINE		X	
BIG SANDY-LANDSMAN CREEK LINE		X	
BIG SANDY-LIMON LINE		X	
BIG SANDY-LINCOLN LINE		X	
BLACK FOREST TAP	X		
BLACK FOREST TAP-BLACK SQUIRREL LINE		X	
BLACK LAKE-SPRINGER LINE LINE		X	
BLACK SQUIRREL-FULLER LINE		X	
BLAZER-CARRIZO CANYON LINE		X	
BLUEDOOR-CORTEZ LINE		X	
BODO-HESPERUS DBL CKT LINE		X	
BONNEY CREEK-BURLING-N LINE		X	
BOONE-LA JUNTA LINE		X	
BOONE-LAMAR LINE		X	
BOYD-LONETREE TAP LINE		X	
BROMLEY- PRAIRIE CENTER LINE		X	
BURLINGTON-BURLINGTON LINE		X	
BURLINGTON-WRAY LINE		X	
BURRO BRIDGE-SUNSHINE LINE		X	
BUSHNELL TAP		X	
CA SUB-CALAMITY RIDGE LINE		X	
CABALLO-MIMBRES LINE		X	
CAHONE-DOE CANYON LINE		X	
CAHONE-EMPIRE LINE		X	
CARMEL-WAVERLY LINE		X	
CARMEL-ZINZER LINE		X	
CASCADE-SILVERTON TAP LINE		X	
CEMEX-DOWE FLATS LINE		X	
CHEYENNE-CO/WY STATE LINE		X	
CINIZA TAP LINE		X	
CLAPHAM-GLADSTONE LINE			X
CO/WY STATE LINE-KEOTA LINE		X	
CO/WY STATE LINE-LRS LINE		X	
CO/WY STATE LINE-PONNEQUIN LINE		X	
COMANCHE-WALSENBURG LINE		X	
CORTEZ PIPELINE TAP		X	
CORTEZ PIPELINE TAP-MAIN SWITCH LINE		X	
CORTEZ PIPELINE TAP-TOWAOC CANAL TAP LINE		X	
CORTEZ-EMPIRE LINE		X	
COW CANYON-HOVENWEEP LINE		X	
COW CANYON-YELLOW JACKET LL LINE		X	
CRAIG-HAYDEN TAP LINE		X	
CRAIG-RIFLE LINE		X	
CUCHILLO TAP	X		
DACONO-ERIE LINE		X	
DAVE JOHNSTON-LRS LINE		X	
DAVIS-DAVIS TAP LINE		X	
DAVIS-GREENHOUSE LINE		X	
DEERING LAKE-NORTH YUMA LINE		X	
DEL CAMINO-RINN VALLEY LINE		X	
DEMING-MIMBRES LINE		X	
DONA ANA-ALAMOGORDO LINE		X	
DOUGHSPOON-GUNNISON VALLEY LINE		X	
DOWE FLATS-LYONS TAP LINE		X	
DURANGO-BAYFIELD LINE		X	
DURANGO-BODO LINE		X	

DURANGO-HESPERUS LINE		X	
DURANGO-SHENANDOAH LINE		X	
E MONTROSE-PEACH VALLEY LINE		X	
E. CORTEZ-BLUEDOOR LINE		X	
ECKLEY-BETHEL LINE		X	
ELEPHANT BUTTE-HOT SPRINGS TAP LINE		X	
ELEPHANT BUTTE-LAS CRUCES LINE		X	
ELEPHANT BUTTE-SOCORRO LINE		X	
EMIL ANDERSON-FOREST LAKES LINE		X	
EMIL ANDERSON-MONUMENT LINE		X	
EMPIRE-LOST CANYON LINE		X	
ERIE-HOYT LINE		X	
FALCON-FULLER LINE		X	
FALCON-GEESEN LINE		X	
FARR-WINDY GAP LINE		X	
FIRESTONE-WHEELER LAKE LINE		X	
FORT WINGATE TAP	X		
FRASER (METTLER)-MILL LINE		X	
FRASER (METTLER)-WINDY GAP LINE		X	
G. MESA TAP-G. MESA SUB LINE		X	
GALLUP-YA-TA-HEY LINE		X	
GARNET MESA TAP		X	
GARNET MESA TAP-HOTCHKISS LINE		X	
GARNET MESA TAP-SUBSTATION LINE		X	
GEESEN-RANCHO LINE		X	
GLADSTONE-CO/NM STATE LINE LINE		X	
GLADSTONE-SPRINGER LINE		X	
GOODMAN POINT-MAIN SWITCH LINE		X	
GORE PASS-BLUE RIVER LINE		X	
GORE PASS-WINDY GAP LINE		X	
GRANBY PUMPING PLANT-WINDY GAP LINE		X	
GRAND JUNCTION-MONTROSE LINE		X	
GRAND JUNCT-MONTROSE LINE		X	
GRANTS-GALLUP LINE		X	
GREAT CUT 115KV TAP		X	
GREENHOUSE-HENRY LAKE LINE		X	
GREENHOUSE-JM SHAFER LINE		X	
GRESHAM-BLACK FOREST TAP LINE		X	
GUNNISON VALLEY-GARNET MESA LINE		X	
HAPPY CANYON-BULLOCK LINE		X	
HAYDEN SUB-AXIAL BASIN LINE		X	
HAYDEN TAP-HAYDEN SUB LINE		X	
HAYDEN TAP-WOLCOT TAP LINE		X	
HAYDEN-AULT LINE		X	
HAYDEN-GORE PASS LINE		X	
HAYDEN-HAYDEN LINE		X	
HAYDEN-STEAMBOAT LINE		X	
HELL CREEK TAP		X	
HELL CREEK TAP-LIBERTY LINE		X	
HENRY LAKE-BROMLEY LINE		X	
HENRY LAKE-SIPRES LINE		X	
HENRY LAKE-STORY LINE		X	
HERNANDEZ-OJO CALIENTE TAP LINE		X	
HESPERUS-CO/NM STATE LINE		X	
HIDALGO-PYRAMID LINE		X	
HOLLOMAN TAP-ALAMOGORDO LINE		X	
HOT SPRINGS TAP	X		
HOT SPRINGS TAP-CABALLO LINE		X	
HOTCHKISS-NORTH FORK LINE		X	
HOVENWEEP-SAND CANYON LINE		X	
JOES-ARICKAREE LINE		X	
KEOTA-REDBOX LINE		X	
KEOTA-STORY LINE		X	
KREMMLING-WINDY GAP LINE		X	
LAJUNTA-WILLOW CREEK LINE		X	
LAMAR-VILAS TAP LINE			X
LIBERTY-JOES LINE		X	
LINCOLN-MIDWAY LINE		X	
LINDON TAP		X	
LINGLE TAP	X		
LOST CANYON-CORTEZ PIPELINE LINE		X	
LOST CANYON-DURANGO LINE		X	
LOST CANYON-E CORTEZ LINE		X	
LOST CANYON-TOWAOC CANAL TAP LINE		X	
LOST CREEK TAP		X	
LOVELL-BIG GEORGE LINE		X	
LRS-AULT LINE		X	
LRS-SIDNEY LINE		X	
LRS-STEGALL LINE		X	
LUDLOW TAP-BURRO CANYON LINE		X	
MAIN SWITCH-MOQUI C LINE		X	
MAINSWITCH-CORTEZ PIPELINE LINE		X	
MANCOS TAP-LOST CANYON LINE		X	
MEADOW-SLATER SUBSTATION LINE		X	
MEEKER-RANGELY LINE		X	
MEEKER-RIFLE LINE		X	
MENDOZA TAP		X	
MIDWAY-BOONE LINE		X	
MIDWAY-RANCHO LINE		X	
MOLAS TAP-SILVERTON TAP LINE		X	
MONOLITH TAP-MONOLITH LINE		X	
MONTROSE-HAPPY CANYON LINE		X	
MONTROSE-HESPERUS LINE		X	
MONTROSE-NUCLA LINE		X	

MONTROSE-SPRING CREEK TAP LINE		X	
MONUMENT-GRESHAM LINE		X	
MYERS 115 KV TAP	X		
NORTH FORK-JUANITA LINE		X	
NORTH MESA-GARNET MESA TAP LINE		X	
NORTH MESA-HOTCHKISS LINE		X	
NORTH YUMA-RED WILLOW LINE		X	
NORTH YUMA-WRAY LINE		X	
NORWOOD-WILSON MESA LINE		X	
NUCLA-CAHONE LINE		X	
NUCLA-SUNSHINE LINE		X	
NUNN-PIERCE LINE		X	
NUNN-ROCKPORT LINE		X	
OJO CALIENTE TAP		X	
OJO CALIENTE TAP-TAOS LINE		X	
OJO-TAOS LINE		X	
OLIVE CREEK TAP		X	
OWL CREEK-PONNEQUIN LINE		X	
OWL CREEK-ROCKPORT LINE		X	
PEGS-BLUEWATER SE TAP LINE		X	
PEGS-GALLUP SW TAP LINE		X	
PEGS-AMBROSIA LINE		X	
PLAZA-ZINZER LINE		X	
PONCHA-SAN LUIS LINE		X	
PROSPECT VALLEY-SAN CREEK TAP LINE		X	
RED WILLOW-WAGES LINE		X	
REUNION-PRAIRIE CENTER LINE		X	
RICHARD LAKE-WAVERLY LINE		X	
RIFLE-GRAND JUNCTION LINE		X	
RIFLE-RIFLE LINE		X	
RINN VALLE-DACONO LINE		X	
RIVERTON-WIND RIVER TAP LINE		X	
SAN LUIS VALLEY-STANLEY LINE		X	
SAN LUIS VALLEY-STANLEY TAP LINE		X	
SAN LUIS VALLEY-WALSENBERG LINE		X	
SAND CANYON-GOOD POINT LINE		X	
SANDHILLS-WRAY LINE		X	
SHENANDOAH-MANCOS TAP LINE		X	
SHIPROCK-FOUR CORNERS LINE		X	
SIDNEY SUB-SIDNEY WAPA LINE		X	
SIDNEY-NORTH YUMA LINE		X	
SILVERTON TAP	X		
SILVERTON TAP-BURRO BRIDGE LINE		X	
SLATER SUBSTATION-DEL CAMINO LINE		X	
SOUTH FORK-BONNEY CREEK LINE		X	
SOUTH FORK-HELL CREEK LINE		X	
SPRING CREEK MESA-BULLOCK LINE		X	
SPRING CREEK TAP		X	
SPRING CREEK TAP-NORTH MESA LINE		X	
STANLEY TAP		X	
STANLEY TAP-WAVERLY LINE		X	
STAR NELSON-DOUGHSPOON LINE		X	
STEAMBOAT TAP		X	
STEGALL WAPA-STEGALL LINE		X	
STEGALL-SIDNEY 23 KV LINE		X	
STEGALL-SIDNEY 345 KV LINE		X	
STEGALL-STEGALL LINE		X	
STEM BEACH-WALSENBURG LINE		X	
STORRIE LAKE-SPRINGER LINE		X	
STORY-STORY LINE		X	
STORY-BEAVER CREEK LINE		X	
STORY-NORTH YUMA LINE		X	
SUNSHINE-WILSON MESA LINE		X	
TAOS-BLACK LAKE LINE		X	
TULAROSA TAP-BLAZER LINE		X	
VERNON TAP-IDALIA LINE		X	
VILAS TAP-VILAS LINE		X	
WAGES-WAUNETA LINE		X	
WALSENBURG-CO/NM STATE LINE		X	
WALSENBURG-LUDLOW TAP LINE		X	
WARY -WARY TAP LINE		X	
WELD-WHITNEY LINE		X	
WEST (SCPC)-STEM BEACH LINE		X	
WHITE SANDS TAP		X	
WHITNEY (CO)-WINDSOR TAP LINE		X	
WILLOW CREEK-VILAS TAP LINE		X	
WIND RIVER TAP		X	
WIND RIVER TAP-PILOT BUTTE LINE		X	
WOLCOT TAP-STEAMBOAT TAP LINE		X	
WOLCOTT TAP-WOLCOTT LINE		X	
WRAY CITY TAP-WRAY LINE		X	
WRAY-ECKLEY LINE		X	
WRAY-VERNON TAP LINE		X	
YELLOW II SWITCH-YELLOW JACKET W LINE		X	
YELLOW JACKET W-MAIN SWITCH LINE		X	

ATTACHMENT E

PREPARED DIRECT TESTIMONY OF RYAN J. HUBBARD

Exhibit No. TS-006

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Tri-State Generation & Transmission	)	Docket No. ER19-___-000
Association, Inc.	)	

PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

RYAN J. HUBBARD

On Behalf of

Tri-State Generation & Transmission Association, Inc.

July 23, 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tri-State Generation & Transmission Association, Inc.	)))	Docket No. ER19-___-000

PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

RYAN J. HUBBARD

On Behalf of

Tri-State Generation & Transmission Association, Inc.

I. INTRODUCTION

Q: What is your name and address?

A: My name is Ryan J. Hubbard. My business address is 1100 West 116th Avenue, Westminster, CO, 80234.

Q: Who do you work for?

A: I work for Tri-State Generation & Transmission Association, Inc. ("Tri-State").

Q: What is your position and general area(s) of responsibility?

A: I am employed as Manager, Bulk Systems Planning and Interconnections. I am responsible for planning, coordinating, directing, and providing engineering support for the development of the Tri-State transmission network.

Q Summarize your educational and professional background

A: I have been employed by Tri-State since 2011, eight years of which as a Transmission Planning Engineer. Prior to joining Tri-State, I worked as an electrical engineer at a

consulting firm for four years. I have undergraduate and master's degrees in engineering from the Colorado School of Mines. I am a registered Professional Engineer in the State of Colorado.

Q: Have you previously testified in regulatory proceedings?

A: No.

Q: Who are you testifying for here?

A: I am testifying on behalf of Tri-State.

Q: What is the purpose of your testimony?

A: I will present the development of Tri-State's Real Power Loss Factor included in its OATT.

Q: Why is Tri-State making this filing at this time?

A: Tri-State has filed to become a Federal Energy Regulatory Commission (FERC) jurisdictional utility. Prior to this filing, Tri-State was a non-jurisdictional utility.

Q: Have you prepared any exhibits in support of your testimony?

A: Yes, the 2018 Transmission System Loss Factor Study performed by Tri-State is attached as Exhibit No. TS-007.

Q: Please summarize your testimony.

A: According to the 2018 Transmission System Loss Factor Study, Tri-State's Real Power Loss factor is 3.378% for transmission service under the Tri-State Open Access Transmission Tariff ("OATT").

II. DESCRIPTION OF TRI-STATE

Q: Provide a brief description of Tri-State

A: Tri-State is a not-for-profit generation and transmission cooperative formed and owned by its 43 member distribution cooperatives and public power systems located in four states:

Colorado, Nebraska, New Mexico, and Wyoming. The territories served by Tri-State's Member Systems covers a total of approximately 200,000 square miles.

Q: What transmission facilities does Tri-State have?

A: Tri-State owns or has capacity interests in approximately 5,665 miles of high-voltage transmission lines and owns or has an ownership interest in major equipment ownership in approximately 409 substations and switchyards. Of the 409 substations and switchyards, Tri-State is responsible for supplying station service power to 268 of them.

Q: How does Tri-State use its transmission facilities?

A: Tri-State utilizes its transmission facilities to serve its Network and Transmission Service Customers with reliable transmission service.

III. REAL POWER LOSS FACTOR

Q: Why has Tri-State developed and included a Real Power Loss Factor in its OATT?

A: Real power loss is an inherent part of the transmission system. A real power loss factor was developed and included in Tri-State's OATT for the electric losses that are expected to occur as a result of point-to-point and network transmission service taken on Tri-State's transmission system.

Q: Has Tri-State performed a transmission line loss study?

A: Yes. A study was completed in May 2019.

Q: What assumptions did Tri-State use in its calculation of the expected transmission system losses?

A: Tri-State calculated transmission system losses from four types of losses: current (I^2R or copper) losses, transformer excitation, substation station service, and corona losses.

Current and transformer excitation losses were calculated using five WECC Operating cases to provide varying load and generation profiles that may exist at different points of the year. The five cases represented heavy summer, light summer, heavy winter, light winter, and heavy spring conditions. It was assumed the heavy summer case represented 332 hours of the year, the light summer case represented 1828 hours of the year, the heavy winter represented 839 hours of the year, the light winter represented 1369 hours of the year, and the heavy spring represented the remaining hours of the year. Only losses on transmission lines and Bulk Electric System (BES) transformers owned by Tri-State were included in the loss calculation. Losses associated with jointly owned transmission lines were divided on a pro rata share based on ownership.

Substation station service losses were assumed to be total load served at 268 substations at an average of 25kW each.

Corona losses were calculated using the following assumptions:

- Elevation: 5600 ft
- Fair Weather: 2 mph Wind, 0.00 inch/hr rainfall, 8615 hours/year
- Foul Weather: 10 mph Wind, 0.12 inch/hr rainfall, 145 hours/year
- Structure Design: Standard RUS Structures for 230 kV, 138 kV, and 115 kV; Lattice Structure for 345 kV
- Foul Weather: 10 mph Wind, 0.12 inch/hr rainfall
- Conductor Size: 345kV – Bundled 1272kcmil ACSR "Bittern"; 230kV – 1272kcmil ACSR "Bittern"; 138kV – 477 kcmil ACSR "Hawk"; 115kV – 477 kcmil ACSR "Hawk"

Q: Please explain the calculation Tri-State performed to determine its expected transmission system losses.

A: The current losses were calculated in each of the five WECC Operating cases by totaling the I^2R losses on Tri-State owned transmission lines and BES transformers. The transformer excitation losses were calculated in each of the five WECC Operating cases by totaling the excitation losses on Tri-State owned BES transformers.

The substation station service loss was calculated by multiplying the estimated losses per substation by the total losses.

The corona losses were calculated using Bonneville Power Administration's "Corona and Field Effects Version 3.1" program. The estimate annual corona losses on Tri-State transmission lines factored in the altitude, design, and mileage of each voltage class, and hours of fair and foul weather conditions.

Q: What values for transmission system losses did Tri-State use to calculate its Real Power Loss Factor?

A: The current and transformer excitation losses in the Heavy Summer, Light Summer, Heavy Winter, Light Winter, and Heavy Spring operating cases were 67.5 MW, 48.7 MW, 53.2 MW, 39.2 MW, and 50.1 MW, respectively. The substation station service and corona losses were calculated to be 6.7 MW and 2.563 MW, respectively. A real loss percentage was calculated by totaling the four types of losses and dividing by the total Tri-State network customer load in the respective operating case. This process equated to a real power loss percentage in the Heavy Summer, Light Summer, Heavy Winter, Light Winter, and Heavy Spring operating cases of 3.57%, 3.25%, 3.24%, 2.95%, and 3.57%, respectively.

Q: Why are these appropriate values for use in determining Tri-State's Real Power Loss factor?

A: The real power loss factor should consider several types of losses experienced on the transmission system over several operated conditions. The use of current, transformer excitation, substation station service, and corona losses in the real power loss factor accomplishes this and allow the creation of an appropriate real power loss percentage to be applied over a full year.

Q: Please explain how Tri-State has determined the Real Power Loss Factor contained in its OATT?

A: The four types of losses were totaled for each Operating case and divided by the total amount of Tri-State network customer load served by Tri-State transmission to determine a percent system loss. Tri-State load served by other entities' transmission under a NITS agreement was excluded from the total load. The percent system loss was then weighted based on assumed hours of operation for each Operating case throughout the year to determine the total weighted real power loss percentage.

Q: What Real Power Loss Factor has Tri-State incorporated into its OATT?

A: The weighted real loss percentage was 3.378%.

Q: Does this conclude your testimony?

A: Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tri-State Generation and Transmission Association, Inc.	))))	**Docket No. ER19-___-000**

AFFIDAVIT OF RYAN J. HUBBARD

Ryan J. Hubbard, being first duly sworn, deposes and says that he is the Ryan J. Hubbard referred to in the foregoing direct testimony, filed on behalf of Tri-State Generation and Transmission Association, Inc., that he has read such testimony, and is familiar with the contents thereof and that the answers therein are true and correct to the best of his knowledge, information, and belief.

Ryan J. Hubbard

Subscribed and sworn to before me this 14th day of July, 2019, by Ryan J. Hubbard proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Notary Public

Commission Expires on: 1/23/2022

TRACI L. PINK
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID #20004015407
My Commission Expires January 23, 2022

TRI-STATE G&T

A Touchstone Energy® Cooperative

2018 Transmission System Loss Factor

Prepared by: Chris Gilden

Reviewed by: Ryan Hubbard

May 24, 2019

Table of Contents

Objective

The objective of this report is to document the process used to determine aggregate Bulk Electric System (BES) transmission losses for Tri-State's transmission system. The losses are used to determine the *Real Power Loss Factor* which is part of Tri-State's Open Access Transmission Tariff. Transmission Customers are charged for electric losses that occur on the system as a result of their load based on the *Real Power Loss Factor*. Losses come in several forms, the largest being associated with current (I^2R or copper losses) and a smaller portion associated with voltage (corona and transformer excitation).

Study Methodology

I^2R and Excitation System Losses

Siemens PTI PSS/E 33.11.0 was used to determine I^2R and Excitation transmission losses. A group of WECC Operating cases were selected to provide varying load and generation levels and profiles that may exist at different points throughout the year. The cases selected were:

1. 2019 Heavy Summer, 19HS3ap.sav
2. 2019 Light Summer, 19LS1ap.sav
3. 2019 Heavy Winter, 19HW3ap.sav
4. 2019 Light Winter, 19LW1ap.sav
5. 2019 Heavy Spring, 19HSP1ap.sav

Due to the high level of integration between Tri-State's system and neighboring utilities, Tri-State has a number of loads that are inherently served by other utilities' BES transmission networks. These loads are not included in the total loss calculation as their losses are associated with other utilities' BES elements. Also not included are losses associated with loads located in the Eastern Interconnection as those losses are determined by Southwest Power Pool (SPP).

PSS/E has functionality to calculate I^2R losses for transmission lines and transformers and Excitation (no-load) losses in transformers by using model data. Using Tri-State's ownership codes, all losses associated with those codes were calculated. Losses from elements with partial ownership were also included as a percentage of ownership. The instantaneous MW loss for each case is listed below in Table 1.

Ownership codes for each case were verified to ensure losses on elements owned by Tri-State were consistently included. Ownership codes for distribution transformers modeled in the cases were altered as to not include losses associated with these elements.

Using coincident system peak data for 2018, the number of hours in a year that each case would represent was determined. An hourly basis allows the calculation of a weighted average of typical system losses. The following criteria were applied to determine the number of hours to be applied for each case:

1. Summer is defined as June 1 – August 31:
    a. Heavy Summer is defined as coincident peak greater than 85% of the highest coincident peak during this time frame.
    b. Light Summer is defined as all other times.
2. Winter is defined as December 1 – February 28:
    a. Heavy Winter is defined as coincident peak greater than 85% of the highest coincident peak during this time frame.
    b. Light Winter is defined as all other times.

3. Heavy Spring/Autumn or "Shoulder" Season
    a. All remaining hours are aggregated under a Heavy Spring/Autumn or "Shoulder" Season case.

Table 1: Case Load Levels and I^2R and Excitation Losses for Tri-State's BES Elements

Case	Total Tri-State Network Load - WECC (MW)	I^2R and Excitation Loss (MW)	Hours per Year of Occurrence	Weighting Factor
2019 Heavy Summer	2148	67.5	340	0.0388
2019 Light Summer	1784	48.7	1868	0.2132
2019 Heavy Winter	1927	53.2	821	0.0937
2019 Light Winter	1643	39.2	1339	0.1529
2019 Heavy Spring	1661	50.1	4392	0.5014
	Total Yearly kWh Loss due to I^2R and Excitation			**430,126,000**
	Average MW Loss due to I^2R and Excitation			**49.101 MW**

Substation Power and Light Losses

Substations require some amount of power to operate devices such as relays, heaters, cooling fans, and lighting. This power is typically unmetered. The amount of power required by a substation can vary significantly based on size and relative complexity. Tri-State estimates that the average power consumption for a given substation is 25 kW. Based on the 268 substations represented by *Tri-State Network Load* - *WECC* in Table 1, this is approximately 6.7 MW or 58,692,000 kWh of additional losses.

Table 2: Substation Power and Light Losses

Case	Number of Tri-State Substations	Average Substation Power Requirement, kW	Hours per Year of Occurrence	Loss due to Substation Energy Requirements, kWh
2019 Heavy Summer	268	25	340	2,278,000
2019 Light Summer	268	25	1868	12,515,600
2019 Heavy Winter	268	25	821	5,550,700
2019 Light Winter	268	25	1339	8,971,300
2019 Heavy Spring	268	25	4392	29,426,000
	Total Yearly kWh Loss due to Substation Power and Light			**58,692,000**
	Average MW Loss due to Substation Power and Light			**6.7 MW**

Corona Losses

Corona is an electric discharge into the air surrounding a conductor. Corona occurs naturally as a byproduct of using high voltage transmission lines and results in some amount of energy leaking into the

air resulting in an electric loss. Several factors influence the magnitude of corona loss including physical transmission line condition (e.g. stranded, dirty, imperfections, etc.), operating voltage, altitude, and weather. Rainy weather conditions can significantly increase corona losses.

Bonneville Power Administration's '*Corona and Field Effects Version 3.1*' program was used to calculate corona losses on Tri-State's 345 kV, 230 kV, 138 kV, and 115 kV transmission lines. Corona losses were calculated for both fair weather and foul weather conditions.

In 2018, National Weather Service-Boulder weather monitoring sites across Colorado[1], averaged 17.25 inches of rain. Assuming 145 hours of rainy hours per year, the average rate of rain fall is approximately 0.12 inch/hour.

The following assumptions were made regarding corona calculations. The tabulated results are shown in Table 3:

1. Elevation: 5600 ft
2. Weather:
    a. Fair Weather: 2 MPH Wind, 0.00 inch/hr rainfall
    b. Foul Weather: 10 MPH Wind, 0.12 inch/hr rainfall
3. Structure Design:
    a. Typical RUS Structure Design Standards for 230 kV, 138 kV, and 115 kV.
    b. A typical Craig – Ault Structure was the basis for the 345 kV line.
        i. The 345 kV line assumes a 2-conductor bundle.
4. Conductors Selection:
    a. 345 kV: 1272 ACSR 45/7 (Bittern)
    b. 230 kV: 1272 ACSR 45/7 (Bittern)
    c. 138 kV: 477 ACSR 26/7 (Hawk)
    d. 115 kV: 477 ACSR 26/7 (Hawk)

[1] Colorado receives the highest annual precipitation for the states Tri-State operates within. Since rainfall has a significant impact on corona losses, the worst-case annual rainfall was used.

Table 3: Corona Loss Tabulation

Voltage Level	Miles of Transmission Line	Fair Weather Corona Loss, kW/mi (2 MPH Wind, 0.0 inch/hr rain)	Foul Weather Corona Loss, kW/mi (10 MPH Wind, 0.12 inch/hr rain)	Hours of Foul Weather per Year	Fair Weather Corona Energy Loss, kWh	Foul Weather Corona Energy Loss, kWh
345 kV	1082	0.957	59.280	145	8,920,608	9,300,439
230 kV	1116	0.193	11.977	145	1,855,567	1,938,118
138 kV	184	0.021	1.302	145	33,288	34,737
115 kV	3119	0.007	0.397	145	18,8091	179,545
			Total Yearly kWh loss due to Corona			**22,450,395**
			Average MW Loss due to Corona			**2.563**

Results

Combining the results of the I^2R and Excitation Losses, Substation Power and Light Losses, and Corona Losses yields the following result:

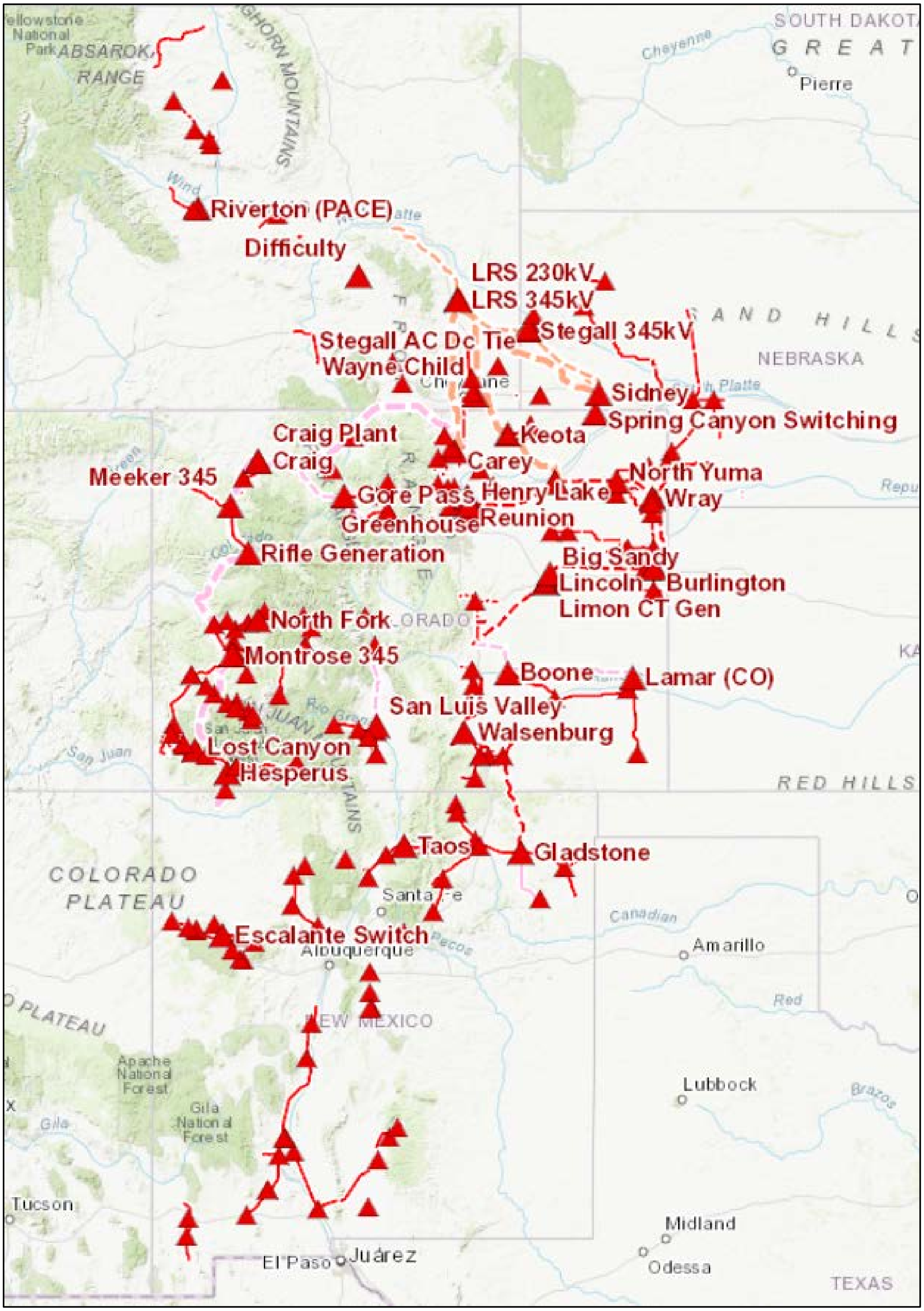
Table 4: Total Tri-State System Losses (WECC)

Case	Total Tri-State Network Load - WECC (MW)	System Loss (MW)	Substation Loss (MW)	Corona Loss (MW)	Hours per Year of Occurrence	BES Loss Percentage
2019 Heavy Summer	2148	67.5	6.7	2.563	340	3.574%
2019 Light Summer	1784	48.7	6.7	2.563	1868	3.249%
2019 Heavy Winter	1927	53.2	6.7	2.563	821	3.242%
2019 Light Winter	1643	39.2	6.7	2.563	1339	2.948%
2019 Heavy Spring	1661	50.1	6.7	2.563	4392	3.574%
			Weighted Total Loss Percentage			**3.378%**

Conclusion

Tri-State's *Real Power Loss Factor* was determined to be 3.378%. This value reflects a typical system loss across different seasonal conditions under varying load and generation profiles. The loss includes transmission line and BES transformer resistive (I^2R) losses, corona losses, BES transformer excitation losses, and substation unmetered power requirements.

Appendix A: Tri-State System Map



Appendix B: Transmission Line and Transformer Ownership

Table B1: *Transmission Line List with Tri-State as Owner or Partial-Owner*

From Bus	To Bus	ID	Owner 1		Owner 2	
AMBROSIA 230.00	PEGS 230.00	1	127	100.00%		
MIMBRES 115.00	ALTLUNTP 115.00	1	127	100.00%		
OJO 345.00	TAOS 345.00	1	127	100.00%		
YAHTAHEY 115.00	GALLUPPG 115.00	1	127	100.00%		
MENDOZAT 115.00	GALLUPPG 115.00	1	127	100.00%		
MENDOZAT 115.00	WINGATE 115.00	1	127	100.00%		
LAS_CRUC 115.00	DONA_ANA 115.00	1	127	100.00%		
ORO_GRAN 115.00	JARILLA1 115.00	1	127	100.00%		
ALAMOGPG 115.00	ALAMOGCP 115.00	1	127	100.00%		
ALGODONE 115.00	SNYSIDRO 115.00	1	127	100.00%		
BELEN_PG 115.00	BERNARD&2MSL115.00	1	127	100.00%		
BERNARDO 115.00	SOCORROP 115.00	1	127	100.00%		
BERNARDO 115.00	BERNARD&1MSL115.00	1	127	100.00%		
BLACKLAK 115.00	SPRINGER 115.00	1	127	100.00%		
BLACKLAK 115.00	TAOS 115.00	1	127	100.00%		
BLUEWATR 115.00	PEGS 115.00	1	127	100.00%		
CABALLOT 115.00	HOT_SPRG 115.00	1	127	100.00%		
CABALLOT 115.00	ALTLUNTP 115.00	1	127	100.00%		
CINIZA 115.00	PEGS 115.00	1	127	100.00%		
CINIZA 115.00	WINGATE 115.00	1	127	100.00%		
CLAPHAM 115.00	ROSEBUD 115.00	1	127	100.00%		
CLAPHAM 115.00	GLADSTON 115.00	1	127	100.00%		
CUCHILLO 115.00	EL_BUTTE 115.00	1	127	100.00%		
CUCHILLO 115.00	HOT_SPRG 115.00	1	127	100.00%		
DONA_ANA 115.00	PICACHO 115.00	1	127	100.00%		
DONA_ANA 115.00	ALAMOGCP 115.00	1	127	100.00%		
EL_BUTTE 115.00	SOCORROP 115.00	1	127	100.00%		
EL_BUTTE 115.00	FRNTIER 115.00	1	127	100.00%		
EL_BUTTE 115.00	ELBUT_US 115.00	1	127	100.00%		
GRANTS 115.00	GRANTS_T 115.00	1	127	100.00%		
HERNANDZ 115.00	OJOCALIT 115.00	1	127	100.00%		
LA_JARA 115.00	TORREON 115.00	1	127	100.00%		
MPC 115.00	PEGS 115.00	1	127	100.00%		
PDPLAYAS 115.00	PLAYAS 115.00	1	127	100.00%		
PICACHO 115.00	FRNTIER 115.00	1	127	100.00%		
PLAYAS 115.00	PYRTAP2 115.00	1	127	100.00%		
SNYSIDRO 115.00	TORREON 115.00	1	127	100.00%		
SPRINGER 115.00	GLADSTON 115.00	1	127	100.00%		
SPRINGER 115.00	RAINVL_T 115.00	1	127	100.00%		

SPRINGER 115.00	BISON 115.00	1	127	100.00%		
STORRIE 115.00	RAINVL_T 115.00	1	127	100.00%		
TAOS 115.00	OJOCALIT 115.00	1	127	100.00%		
WILLARD 115.00	TORRANCE 115.00	1	127	100.00%		
YORKCANY 115.00	VANBREMR 115.00	1	127	100.00%		
PYRTAP1 115.00	PYRAMID 115.00	1	127	100.00%		
PYRTAP1 115.00	HIDALGO 115.00	1	127	100.00%		
PYRAMID 115.00	PYRTAP2 115.00	1	127	100.00%		
PYRAMID 115.00	HIDALGO 115.00	1	127	100.00%		
GLADSTON 115.00	HESS_TAP 115.00	1	127	100.00%		
GLADSTON 230.00	GLDSTNPS 230.00	2	127	100.00%		
TORRANCE 115.00	DURAN 115.00	1	127	100.00%		
OJOCALIT 115.00	OJOCALI 115.00	1	127	100.00%		
HESSBDW 115.00	HESS_TAP 115.00	1	127	100.00%		
RAINVL1 115.00	RAINVL_T 115.00	1	127	100.00%		
BLAZER_T 115.00	C_CANYON 115.00	1	127	100.00%		
BLAZER_T 115.00	TULAROSA 115.00	1	127	100.00%		
C_CANYON 115.00	RUIDOSO 115.00	1	127	100.00%		
BISON 115.00	VANBREMR 115.00	1	127	100.00%		
BISON 115.00	CIMARRON 115.00	1	127	100.00%		
HESS_TAP 115.00	BUEYEROS 115.00	1	127	100.00%		
GLDSTNPS 230.00	WALSENBG 230.00	1	127	100.00%		
ALTLUNTP 115.00	ALTALUNA 115.00	1	127	100.00%		
TURLY_S 115.00	BLANCO 115.00	1	73	100.00%		
GLADETAP 115.00	ELPASOTP 115.00	1	73	100.00%		
FT CREEK 230.00	ARLNGTN 230.00	1	73	100.00%		
PLATTE 115.00	TROWBRDG 115.00	1	73	100.00%		
SNISABEL 115.00	LUDLOTAP 115.00	1	73	100.00%		
SNISABEL 115.00	PINONCYN 115.00	1	73	100.00%		
BLUERIVR 115.00	MILL 115.00	1	73	100.00%		
BNAVST 115.00	BNVSTATP 115.00	1	73	100.00%		
BOONE 115.00	LAJUNTAT 115.00	1	73	100.00%		
BOONE 230.00	LAMAR_CO 230.00	1	65	56.00%	73	44.00%
BOONE 230.00	MIDWAYPS 230.00	1	65	50.00%	73	50.00%
BURROCYN 115.00	LUDLOTAP 115.00	1	73	100.00%		
LAMSO 115.00	LAJUNTAT 115.00	1	73	100.00%		
LAMSO 115.00	WILOW_CK 115.00	1	73	100.00%		
GOREPASS 230.00	HDN EAST 230.00	1	73	60.70%	65	39.30%
COMANCHE 230.00	WALSENBG 230.00	1	73	100.00%		
SWALLOWS 115.00	DIAMNDBK 115.00	1	73	100.00%		
DIAMNDBK 115.00	PUEB_W 115.00	1	73	100.00%		
LAMAR_CO 115.00	VILAS 115.00	1	73	100.00%		
LAMAR_CO 115.00	WILOW_CK 115.00	1	73	100.00%		

LUDLOTAP 115.00	WALSENBG 115.00	1	73	100.00%		
MILL 115.00	PORTAL 115.00	1	73	100.00%		
MILL 115.00	FRASER 115.00	1	73	100.00%		
PUEB_W 115.00	PUEB_TP 115.00	1	73	100.00%		
PUEB_TP 115.00	STMBEACH 115.00	1	73	100.00%		
PUEB_TP 115.00	W.STATON 115.00	1	73	100.00%		
RAMON 115.00	PLAZA 115.00	1	73	100.00%		
S.ACACIO 115.00	STOCKADE 115.00	1	73	100.00%		
SANLSVLY 115.00	STANLEY 115.00	1	73	100.00%		
SANLSVLY 115.00	WAVERLY 115.00	1	73	100.00%		
SANLSVLY 230.00	PONCHABR 230.00	1	65	50.00%	73	50.00%
STANLEY 115.00	PLAZA 115.00	1	73	100.00%		
STMBEACH 115.00	WALSENBG 115.00	1	73	100.00%		
STOCKADE 115.00	WAVERLY 115.00	1	73	100.00%		
TWNLAKES 115.00	TWNLAKTP 115.00	1	73	100.00%		
WAVERLY 115.00	CARMEL 115.00	1	73	100.00%		
JMSHAFER 230.00	GREENHSE 230.00	1	73	100.00%		
BERTHOUD 115.00	GATEWY 115.00	1	73	100.00%		
BERTHOUD 115.00	LONETREE 115.00	1	73	100.00%		
HENRYLAK 230.00	GREENHSE 230.00	1	73	100.00%		
HENRYLAK 230.00	SIPRES 230.00	1	73	100.00%		
HENRYLAK 230.00	STORY 230.00	1	73	100.00%		
HENRYLAK 115.00	BROMLEY 115.00	1	73	100.00%		
BROMLEY 115.00	PRARI_TS 115.00	1	73	100.00%		
REUNION 115.00	PRARI_TS 115.00	1	73	100.00%		
GREENHSE 115.00	DAVIS_TS 115.00	1	73	100.00%		
GREENHSE 115.00	DAVIS_TS 115.00	2	73	100.00%		
CARMEL 115.00	ZINZER 115.00	1	73	100.00%		
ZINZER 115.00	PLAZA 115.00	1	73	100.00%		
E_YUMA_T 115.00	PANDA_T 115.00	1	73	100.00%		
PANDA_T 115.00	SCHRAMM 115.00	1	73	100.00%		
WRAY TAP 115.00	SANDHILL 115.00	1	73	100.00%		
WRAY TAP 115.00	WRAY 115.00	1	73	100.00%		
WRAY TAP 115.00	WRAY WAPA 115.00	1	73	100.00%		
CALHANTP 115.00	PEYTON 115.00	1	73	100.00%		
SLATERTS 115.00	DEL CTAP 115.00	1	73	100.00%		
SLATERTS 115.00	DELCAMIN 115.00	1	73	100.00%		
BURDETT 115.00	N.YUMA 115.00	1	73	100.00%		
OLIVE CK 115.00	OLIVETAP 115.00	1	73	100.00%		
OLIVETAP 115.00	VERNONTP 115.00	1	73	100.00%		
OLIVETAP 115.00	WRAY 115.00	1	73	100.00%		
KEOTA 345.00	LAR.RIVR 345.00	1	73	100.00%		
KEOTA 345.00	STORY 345.00	1	73	100.00%		

KEOTA 115.00	REDBOX 115.00	1	73	100.00%		
KEOTA 115.00	REDBOX 115.00	2	73	100.00%		
KEOTA 115.00	CHLKBLFF 115.00	1	73	100.00%		
REDBOX 115.00	REDTAIL 115.00	1	73	100.00%		
REDBOX 115.00	REDTAIL 115.00	2	73	100.00%		
HESPERUS2 115.00	SUNNYSDE 115.00	1	73	100.00%		
HESPERUS2 115.00	HESPERUS 115.00	1	73	100.00%		
HESPERUS2 115.00	COYOTE G 115.00	1	73	100.00%		
GATEWY 115.00	BOYD 115.00	1	73	100.00%		
ERIE SW 230.00	SIPRES 230.00	1	73	100.00%		
SPRNGCK 115.00	HESPERUS 115.00	1	73	100.00%		
SPRNGCK 115.00	TAMARRON 115.00	1	73	100.00%		
S_KERSEY 115.00	KERSEY_W 115.00	1	73	100.00%		
DOWEFLAT 115.00	LYONS 115.00	1	73	100.00%		
DOWEFLAT 115.00	ROCKMTCM 115.00	1	73	100.00%		
VOLLMERT 115.00	VOLLMER 115.00	1	73	100.00%		
VOLLMERT 115.00	BLK SQMV 115.00	1	73	100.00%		
VOLLMERT 115.00	FULLER 115.00	1	73	100.00%		
LINDON 115.00	ANTON 115.00	1	73	100.00%		
LINDON 115.00	LSCHANCE 115.00	1	73	100.00%		
ALKALI 115.00	CRSTBUTT 115.00	1	73	100.00%		
ALKALI 115.00	SKITO 115.00	1	73	100.00%		
LANDSMCK 230.00	KITCARSN 230.00	1	73	100.00%		
LANDSMCK 230.00	B.SANDY 230.00	1	73	100.00%		
LANDSMCK 230.00	BURLNGTN 230.00	1	73	100.00%		
HESPXR1 13.800	HESPXR2 13.800	1	73	100.00%		
HESPXR3 13.800	HESPXR4 13.800	1	73	100.00%		
COWCREEK 115.00	RIDGEWAY 115.00	1	73	100.00%		
COWCREEK 115.00	DALLASCR 115.00	1	73	100.00%		
COWCREEK 115.00	SOCANAL 115.00	1	73	100.00%		
GRANDVW 115.00	DURANGO 115.00	1	73	100.00%		
GRANDVW 115.00	BAYFIELD 115.00	1	73	100.00%		
SUNNYSDE 115.00	FLOR.RIV 115.00	1	73	100.00%		
RCKCREEK 115.00	IRONHRS 115.00	1	73	100.00%		
RCKCREEK 115.00	AM EAST 115.00	1	73	100.00%		
IRONHRS 115.00	SALVADOR 115.00	1	73	100.00%		
IRONHRS 115.00	FLOR.RIV 115.00	1	73	100.00%		
GOODMNPT 115.00	MAIN CO 115.00	1	73	100.00%		
GOODMNPT 115.00	SANDCANY 115.00	1	73	100.00%		
DOECANYN 115.00	ANASAZI 115.00	1	73	100.00%		
DOECANYN 115.00	AIR_PROD 115.00	1	73	100.00%		
DOECANYN 115.00	CAHONE 115.00	1	73	100.00%		
ANASAZI 115.00	Y.JACK 2 115.00	1	73	100.00%		

CORTZPIP 115.00	MAIN CO 115.00	1	73	100.00%		
CORTZPIP 115.00	TOWAOC 115.00	1	73	100.00%		
COWCANYN 115.00	HOVENWEP 115.00	1	73	100.00%		
COWCANYN 115.00	Y.JACK 2 115.00	1	73	100.00%		
NORWOOD 115.00	WILSNMSA 115.00	1	73	100.00%		
NORWOOD 115.00	NUCLA 115.00	1	73	100.00%		
WILSNMSA 115.00	SUNSH SM 115.00	1	73	100.00%		
EMONTROS 115.00	PEACHVLY 115.00	1	73	100.00%		
PEACHVLY 115.00	NORTHMSA 115.00	1	73	100.00%		
PEACHVLY 115.00	GARNETAP 115.00	1	73	100.00%		
WL_CHILD 230.00	ARCHER 230.00	1	73	100.00%		
MONO_TP 115.00	MONOLTH 115.00	1	73	100.00%		
IRONTAP 115.00	IRONCRK 115.00	1	73	100.00%		
IRONTAP 115.00	BGEORGE 115.00	1	73	100.00%		
IRONTAP 115.00	LOVELL 115.00	1	73	100.00%		
ALVIN 115.00	SANDHILL 115.00	1	73	100.00%		
ALVIN 115.00	WAUNETA 115.00	1	73	100.00%		
ALVIN 115.00	CRETESWT 115.00	1	73	100.00%		
ANTON 115.00	ARICKARE 115.00	1	73	100.00%		
ARAPASUB 115.00	WAANIBE 115.00	1	73	100.00%		
ARICKARE 115.00	JOES 115.00	1	73	100.00%		
AULT 345.00	LAR.RIVR 345.00	1	73	100.00%		
AULT 345.00	CRAIG 345.00	1	73	50.00%	26	50.00%
B.CK TRI 115.00	BEAVERCK 115.00	1	73	100.00%		
B.CK TRI 230.00	STORY 230.00	1	73	100.00%		
B.SANDY 115.00	LIMON 115.00	1	73	100.00%		
B.SANDY 230.00	LINCOLNT 230.00	1	73	100.00%		
BONNY CK 115.00	BURLNGTN 115.00	1	73	100.00%		
BONNY CK 115.00	SO. FORK 115.00	1	73	100.00%		
BURL PSC 115.00	WANIBETP 115.00	1	73	100.00%		
BURL PSC 115.00	BURL KC 115.00	1	73	100.00%		
BURLNGTN 115.00	BURL KC 115.00	1	73	100.00%		
BURLNGTN 230.00	WRAY 230.00	1	73	100.00%		
BUSHNELL 115.00	BUSHNLTP 115.00	1	73	100.00%		
CHEYENNE 115.00	PONNEQUI 115.00	1	73	100.00%		
DEERINGL 115.00	N.YUMA 115.00	1	73	100.00%		
DEL CTAP 115.00	MEADOW 115.00	1	73	100.00%		
DELCAMIN 115.00	RINNVALL 115.00	1	73	100.00%		
ECKLEY 115.00	ROBB 115.00	1	73	100.00%		
ECKLEY 115.00	BETHELLM 115.00	1	73	100.00%		
FRASER 138.00	WINDYGAP 138.00	1	73	100.00%		
GOREPASS 138.00	WINDYGAP 138.00	1	73	100.00%		
HDOME 115.00	JIMRDYTP 115.00	1	73	100.00%		

HELL CK 115.00	HELL TAP 115.00	1	73	100.00%		
HELL CK 115.00	SAGEBRSH 115.00	1	73	100.00%		
HELL TAP 115.00	LIBERTY 115.00	1	73	100.00%		
HELL TAP 115.00	SO. FORK 115.00	1	73	100.00%		
HRSTHTAP 115.00	TRILBY 115.00	1	73	100.00%		
HRSTHTAP 115.00	MASONVIL 115.00	1	73	100.00%		
IDALIA 115.00	SO. FORK 115.00	1	73	100.00%		
IDALIA 115.00	VERNONTP 115.00	1	73	100.00%		
JIMREADY 115.00	JIMRDYTP 115.00	1	73	100.00%		
JOES 115.00	LIBERTY 115.00	1	73	100.00%		
KODAK 115.00	WHITNEY 115.00	1	73	100.00%		
KODAK 115.00	WHITNEY 115.00	2	73	100.00%		
LAPORTE 115.00	BELLVUTP 115.00	1	73	100.00%		
LOST CK 115.00	LOSTCKTP 115.00	1	73	100.00%		
MAY 115.00	OASISTAP 115.00	1	73	100.00%		
MYERS 115.00	MYERS TP 115.00	1	73	100.00%		
N.YUMA 115.00	REDWILLW 115.00	1	73	100.00%		
N.YUMA 230.00	STORY 230.00	1	73	100.00%		
N.YUMA 230.00	WRAY 230.00	1	73	100.00%		
NCWCD 138.00	WINDYGAP 138.00	1	73	100.00%		
NUNN 115.00	ROCKPRTP 115.00	1	73	100.00%		
NUNN 115.00	AULT 115.00	1	73	100.00%		
PILOT BU 115.00	WINDRIVT 115.00	1	73	100.00%		
POLE CK 115.00	QUALLS 115.00	1	73	100.00%		
RADERVIL 115.00	ERVAYBAS 115.00	1	73	100.00%		
REDWILLW 115.00	WAGES 115.00	1	73	100.00%		
RICHARDS 115.00	WAVER PV 115.00	1	73	100.00%		
RIVERTON 115.00	WINDRIVT 115.00	1	73	100.00%		
ROCKPRTP 115.00	OWL_CRK 115.00	1	73	100.00%		
ROUNDTOP 115.00	SENTINEL 115.00	1	73	100.00%		
SIDNEY 230.00	STEGALL_W 230.00	1	73	100.00%		
SMOKYHLW 115.00	WANIBETP 115.00	1	73	100.00%		
STEGALDC 230.00	STEGALL_E 230.00	1	73	100.00%		
TCAPS 115.00	THERMOPL 115.00	1	73	100.00%		
TCAPS 115.00	JIMRDYTP 115.00	1	73	100.00%		
TIMNATH 115.00	BOXELDER 115.00	1	73	100.00%		
VERNONTP 115.00	VERNONLM 115.00	1	73	100.00%		
WAANIBE 115.00	WANIBETP 115.00	1	73	100.00%		
WAGES 115.00	WAUNETA 115.00	1	73	100.00%		
WILDCAT 115.00	EMIGRANT 115.00	1	73	100.00%		
WINDRIVR 115.00	WINDRIVT 115.00	1	73	100.00%		
BELLEVUE 115.00	BELLVUTP 115.00	1	73	100.00%		
BELLVUTP 115.00	RIPPLE 115.00	1	73	100.00%		

RIPPLE 115.00	WELL TP 115.00	1	73	100.00%		
DUTONBAS 115.00	ERVAYBAS 115.00	1	73	100.00%		
BETHELLM 115.00	VERNONLM 115.00	1	73	100.00%		
CSOC 115.00	GEESEN 115.00	1	73	100.00%		
EMIL AND 115.00	MONUMENT 115.00	1	73	100.00%		
EMIL AND 115.00	FORESTLK 115.00	1	73	100.00%		
FALCONMV 115.00	GEESEN 115.00	1	73	100.00%		
FALCONMV 115.00	FULLER 115.00	1	73	100.00%		
GEESEN 115.00	LORSONRH 115.00	1	73	100.00%		
MIDWAYBR 115.00	RANCHO 115.00	1	73	100.00%		
MIDWAYBR 230.00	LINCOLNT 230.00	1	73	100.00%		
MONUMENT 115.00	GRESHAM 115.00	1	73	100.00%		
RANCHO 115.00	LORSONRH 115.00	1	73	100.00%		
WINDSORT 115.00	WHITNEY 115.00	1	73	100.00%		
GRESHAM 115.00	BLKFORTP 115.00	1	73	100.00%		
BLACKFOR 115.00	BLKFORTP 115.00	1	73	100.00%		
BLKFORTP 115.00	BLK SQMV 115.00	1	73	100.00%		
PEYTON 115.00	MERDNRCH 115.00	1	73	100.00%		
MERDNRCH 115.00	BLK SQMV 115.00	1	73	100.00%		
WELL TP 115.00	WAVER PV 115.00	1	73	100.00%		
RINNVALL 115.00	DACONO 115.00	1	73	100.00%		
DACONO 115.00	ERIE SW 115.00	1	73	100.00%		
PONNEQUI 115.00	OWL_CRK 115.00	1	73	100.00%		
BRACEWLL 115.00	WHITNEY 115.00	1	73	100.00%		
BRACEWLL 115.00	WHITNEY 115.00	2	73	100.00%		
AXIAL 138.00	HAYDEN 138.00	1	73	100.00%		
AXIAL 138.00	MEEKER 138.00	1	73	100.00%		
BLUEMESA 115.00	LAKECITY 115.00	1	73	100.00%		
CAHONE 115.00	NUCLA 115.00	1	73	100.00%		
CAHONE 115.00	GRCUT TP 115.00	1	73	100.00%		
CORTEZ 115.00	BLUEDOOR 115.00	1	73	100.00%		
CORTEZ 115.00	EMPIRETS 115.00	1	73	100.00%		
CRAIG 230.00	HDN WEST 230.00	2	73	59.20%	65	40.80%
CRAIG 345.00	MEEKER 345.00	1	73	55.40%	65	44.60%
DURANGO 115.00	HESPERUS 115.00	1	73	100.00%		
DURANGO 115.00	BODO 115.00	1	73	100.00%		
DURANGO 115.00	SHENDOAH 115.00	1	73	100.00%		
GRANDJCT 115.00	STRNELSN 115.00	1	73	100.00%		
GRANDJCT 345.00	MONTROSE 345.00	1	26	66.70%	73	33.30%
GRANDJCT 345.00	RIFLE_CU 345.00	1	73	58.10%	26	41.90%
HOTCHKIS 115.00	NORTHFRK 115.00	1	73	100.00%		
HOTCHKIS 115.00	GARNETAP 115.00	1	73	100.00%		
LOSTCANY 115.00	E.CORTEZ 115.00	1	73	100.00%		

LOSTCANY 115.00	EMPIRETS 115.00	1	73	100.00%		
LOSTCANY 115.00	MANCOSTP 115.00	1	73	100.00%		
LOSTCANY 115.00	TOWAOC 115.00	1	73	100.00%		
MEEKER 138.00	RIFLE_CU 138.00	1	73	100.00%		
MEEKER 138.00	W.RV.CTY 138.00	1	73	100.00%		
MONTROSE 115.00	NUCLA 115.00	1	73	100.00%		
MONTROSE 115.00	HAPPYCAN 115.00	1	73	100.00%		
MONTROSE 115.00	SPRCKTAP 115.00	1	73	100.00%		
MONTROSE 115.00	STRNELSN 115.00	1	73	100.00%		
MONTROSE 345.00	HESPERUS 345.00	1	26	57.50%	73	42.50%
NORTHFRK 115.00	JUANITA 115.00	1	73	100.00%		
RIFLE_CU 230.00	RIFLE WA 230.00	1	73	72.90%	26	27.10%
HESPERUS 115.00	BODO 115.00	1	73	100.00%		
HESPERUS 345.00	WATRFLW 345.00	1	26	66.70%	73	33.30%
BLUEDOOR 115.00	E.CORTEZ 115.00	1	73	100.00%		
EMPIRETS 115.00	GRCUT TP 115.00	1	73	100.00%		
AM EAST 115.00	BAYFIELD 115.00	1	73	100.00%		
BAYFIELD 115.00	PAGOSA 115.00	1	73	100.00%		
BULLOCK 115.00	HAPPYCAN 115.00	1	73	100.00%		
BULLOCK 115.00	SPRCKTAP 115.00	1	73	100.00%		
CASCADEL 115.00	TAMARRON 115.00	1	73	100.00%		
CASCADEL 115.00	COALBANK 115.00	1	73	100.00%		
JUANITA 115.00	SYLVSTGU 115.00	1	73	100.00%		
NORTHMSA 115.00	SPRCKTAP 115.00	1	73	100.00%		
SHENDOAH 115.00	MANCOSTP 115.00	1	73	100.00%		
GARNET M 115.00	GARNETAP 115.00	1	73	100.00%		
GARNET M 115.00	GUNVAL 115.00	1	73	100.00%		
HOVENWEP 115.00	SANDCANY 115.00	1	73	100.00%		
MAIN CO 115.00	Y.JACK W 115.00	1	73	100.00%		
MAIN CO 115.00	MOQUI C 115.00	1	73	100.00%		
Y.JACK 2 115.00	Y.JACK W 115.00	1	73	100.00%		
DOUGHSPN 115.00	STRNELSN 115.00	1	73	100.00%		
DOUGHSPN 115.00	GUNVAL 115.00	1	73	100.00%		
SUNSH SM 115.00	AMES 115.00	1	73	100.00%		
COYOTE G 115.00	ELPASOTP 115.00	1	73	100.00%		
BURROBDG 115.00	SILVERTN 115.00	1	73	100.00%		
BURROBDG 115.00	AMES 115.00	1	73	100.00%		
COALBANK 115.00	MOLASTAP 115.00	1	73	100.00%		
MOLASTAP 115.00	SILVERTN 115.00	1	73	100.00%		
SILVERTN 115.00	CEMNT CK 115.00	1	73	100.00%		
W.RV.CTY 138.00	CALAMRDG 138.00	1	73	100.00%		
CALAMRDG 138.00	C-A 138.00	1	73	100.00%		
MEEKER 345.00	MCBRYDE 345.00	1	73	100.00%		

BERNARD&2MSL115.0	BERNARD&1MSL115.0	1	127	100.00%		

Table B2: Transformer List with Tri-State as Owner or Partial-Owner

From Bus	To Bus	ID	Owner 1		Owner 2	
CABEZON 345.00	TORREON 115.00	T2	127	100.0%		
PEGS 115.00	PEGS 230.00	1	127	100.0%		
PEGS 230.00	PEGS1 17.600	1	127	100.0%		
TAOS 115.00	TAOS 345.00	1	127	100.0%		
TAOS 115.00	TAOS 345.00	2	127	100.0%		
PYRAMID 115.00	PYRMDG1 13.800	1	127	100.0%		
PYRAMID 115.00	PYRMDG2 13.800	1	127	100.0%		
GLADSTON 115.00	GLADSTON 230.00	1	127	100.0%		
GLADSTON 115.00	GLADSTON 230.00	2	127	100.0%		
GLADSTON 230.00	GLDSTNPS 230.00	1	127	100.0%		
RIVERTON 230.00	RIVERTON 115.00	1	73	100.0%		
THERMOPL 230.00	THERPACE 115.00	2	73	100.0%		
GOREPASS 230.00	GOREPASS 138.00	1	73	100.0%		
LAMAR_CO 115.00	LAMAR_C2 230.00	T1	73	100.0%		
LAMAR_CO 115.00	LAMAR_C2 230.00	T2	73	100.0%		
SANLSVLY 115.00	SANLSVLY 230.00	T1	65	50.0%	73	50.0%
SANLSVLY 115.00	SANLSVLY 230.00	T2	65	50.0%	73	50.0%
WALSENBG 115.00	WALSENBG 230.00	T2	73	100.0%		
WALSENBG 115.00	WALSENBG 230.00	T3	73	100.0%		
JMSHAFR4 13.800	JMSHAFER 230.00	U4	73	100.0%		
JMSHAFER 230.00	JMSHAFR3 13.800	U3	73	100.0%		
JMSHAFER 230.00	JMSHAFR2 13.800	U2	73	100.0%		
JMSHAFER 230.00	JMSHAFR1 13.800	U1	73	100.0%		
HENRYLAK 230.00	HENRYLAK 115.00	T1	73	100.0%		
REUNION 230.00	REUNION 115.00	T1	73	100.0%		
GREENHSE 230.00	GREENHSE 115.00	1	73	100.0%		
GREENHSE 230.00	GREENHSE 115.00	2	73	100.0%		
KEOTA 345.00	KEOTA 115.00	1	73	100.0%		
KEOTA 345.00	KEOTA 115.00	2	73	100.0%		
GATEWY 115.00	GATEWY 230.00	1	73	100.0%		
ERIE SW 230.00	ERIE SW 115.00	T1	73	100.0%		
RIDGEWAY 115.00	RIDGEWAY 4.2000	1	73	100.0%		
B.CK TRI 115.00	B.CK TRI 230.00	1	73	100.0%		
B.SANDY 115.00	B.SANDY 230.00	1	73	100.0%		
BURLNGTN 115.00	BURLNGTN 230.00	1	73	100.0%		
BURLNGTN 115.00	BURLNGTN 230.00	2	73	100.0%		
BURLNGTN 115.00	BRLNGTN1 13.800	1	73	100.0%		
BURLNGTN 115.00	BRLNGTN2 13.800	1	73	100.0%		
FRASER 138.00	FRASER 115.00	1	73	100.0%		

GREYBULL 34.500	NAHNEJEN 115.00	1	73	100.0%		
N.YUMA 115.00	N.YUMA 230.00	1	73	100.0%		
SIDNEY 115.00	SIDNEY 230.00	1	73	100.0%		
STEGALL_W 115.00	STEGALL_W 230.00	2	73	100.0%		
STORY 230.00	STORY 345.00	1	73	100.0%		
STORY 230.00	STORY 345.00	2	73	100.0%		
WRAY 115.00	WRAY 230.00	1	73	100.0%		
FULLER 230.00	FULLER 115.00	1	73	100.0%		
LINCOLNT 230.00	LINCOLN1 13.800	1	73	100.0%		
LINCOLNT 230.00	LINCOLN2 13.800	1	73	100.0%		
CRAIG 230.00	CRAIG 345.00	1	73	100.0%		
CRAIG 230.00	CRAIG 345.00	2	73	100.0%		
CRAIG 230.00	CRAIG 1 22.000	1	73	100.0%		
CRAIG 230.00	CRAIG 2 22.000	1	73	100.0%		
CRAIG 345.00	CRAIG 3 22.000	1	73	100.0%		
LOSTCANY 115.00	LOSTCANY 230.00	1	73	100.0%		
LOSTCANY 115.00	LOSTCANY 230.00	2	73	100.0%		
MONTROSE 115.00	MONTROSE 345.00	1	73	100.0%		
NORTHFRK 115.00	NORTHFRK 230.00	1	73	100.0%		
NORTHFRK 115.00	NORTHFRK 230.00	2	73	100.0%		
NUCLA 115.00	NUCLA 1 13.800	1	73	100.0%		
NUCLA 115.00	NUCLA 2 13.800	1	73	100.0%		
NUCLA 115.00	NUCLA 3 13.800	1	73	100.0%		
NUCLA 115.00	NUCLA 4 13.800	1	73	100.0%		
AMATLAS 230.00	QFATLAS1 13.800	1	73	100.0%		
AMATLAS 230.00	QFATLAS2 13.800	1	73	100.0%		
MCBRYDE 138.00	MCBRYDE 345.00	1	73	100.0%		
HESPERUS 345.00	HESPERUS 115.00	1	73	100.0%		
HESPERUS 345.00	HESPERUS 115.0	2	73	100.0%		

Appendix C: Corona Calculation Inputs

Bonneville Power Administration's Corona and Field Effects tool can be downloaded directly from https://www.bpa.gov/.

345 kV Line Fair Weather:

```
1,0,3,5,345.0,2.00,0.0,5600.00
'ALL'
4.921,6.562,9.842,0.000,1.000,75.000,3.280,4.000,3.280
'PH.A-1','A',22.000,20.500,2,1.345,18.000,199.2,0.000,0.850,0.
'PH.B-1','A',0.000,20.500,2,1.345,18.000,199.2,-120.000,0.850,0.
'PH.C-1','A',-22.000,20.500,2,1.345,18.000,199.2,120.000,0.850,0.
'GND1-1','A',16.75,64.3,1,0.495,0.000,0.000,0.000,0.000,0.
'GND2-1','A',-16.75,64.3,1,0.495,0.000,0.000,0.000,0.000,0.
10,0,3
10,105,10
5,205,50
0,0,0
```

345 kV Line Foul Weather:

```
1,0,3,5,345.0,10.00,0.120,5600.00
'ALL'
4.921,6.562,9.842,0.000,1.000,75.000,3.280,4.000,3.280
'PH.A-1','A',22.000,20.500,2,1.345,18.000,199.2,0.000,0.850,0.
'PH.B-1','A',0.000,20.500,2,1.345,18.000,199.2,-120.000,0.850,0.
'PH.C-1','A',-22.000,20.500,2,1.345,18.000,199.2,120.000,0.850,0.
'GND1-1','A',16.75,64.3,1,0.495,0.000,0.000,0.000,0.000,0.
'GND2-1','A',-16.75,64.3,1,0.495,0.000,0.000,0.000,0.000,0.
10,0,3
10,105,10
5,205,50
0,0,0
```

230 kV Line Fair Weather:

```
1,0,3,5,230.0,2.00,0.0,5600.00
'ALL'
4.921,6.562,9.842,0.000,1.000,75.000,3.280,4.000,3.280
'PH.A-1','A',19.500,33.000,1,1.345,18.000,132.79,0.000,0.850,0.
'PH.B-1','A',0.000,33.000,1,1.345,18.000,132.79,-120.000,0.850,0.
'PH.C-1','A',-19.500,33.000,1,1.345,18.000,132.79,120.000,0.850,0.
'GND1-1','A',10.75,61.5,1,0.435,0.000,0.000,0.000,0.000,0.
'GND2-1','A',-10.75,61.5,1,0.435,0.000,0.000,0.000,0.000,0.
10,0,3
10,105,10
5,205,50
0,0,0
```

230 kV Line Foul Weather:

```
1,0,3,5,230.0,10.00,0.120,5600.00
'ALL'
4.921,6.562,9.842,0.000,1.000,75.000,3.280,4.000,3.280
'PH.A-1','A',19.500,33.000,1,1.345,18.000,132.79,0.000,0.850,0.
'PH.B-1','A',0.000,33.000,1,1.345,18.000,132.79,-120.000,0.850,0.
'PH.C-1','A',-19.500,33.000,1,1.345,18.000,132.79,120.000,0.850,0.
'GND1-1','A',10.75,61.5,1,0.435,0.000,0.000,0.000,0.000,0.
'GND2-1','A',-10.75,61.5,1,0.435,0.000,0.000,0.000,0.000,0.
10,0,3
10,105,10
5,205,50
0,0,0
```

138 kV Line Fair Weather:

```
1,0,3,5,115.0,2.00,0.00,5600.00
'ALL'
4.921,6.562,9.842,0.000,1.000,75.000,3.280,4.000,3.280
'PH.A-1','A',12.500,27.500,1,0.858,18.000,76.67,0.000,0.850,0.
'PH.B-1','A',0.000,27.500,1,0.858,18.000,76.67,-120.000,0.850,0.
'PH.C-1','A',-12.500,27.500,1,0.858,18.000,76.67,120.000,0.850,0.
'GND1-1','A',6.25,41.4,1,0.360,0.000,0.000,0.000,0.000,0.
'GND2-1','A',-6.25,41.4,1,0.360,0.000,0.000,0.000,0.000,0.
10,0,3
10,105,10
5,205,50
0,0,0
```

138 kV Line Foul Weather:

```
1,0,3,5,115.0,10.00,0.12,5600.00
'ALL'
4.921,6.562,9.842,0.000,1.000,75.000,3.280,4.000,3.280
'PH.A-1','A',12.500,27.500,1,0.858,18.000,76.67,0.000,0.850,0.
'PH.B-1','A',0.000,27.500,1,0.858,18.000,76.67,-120.000,0.850,0.
'PH.C-1','A',-12.500,27.500,1,0.858,18.000,76.67,120.000,0.850,0.
'GND1-1','A',6.25,41.4,1,0.360,0.000,0.000,0.000,0.000,0.
'GND2-1','A',-6.25,41.4,1,0.360,0.000,0.000,0.000,0.000,0.
10,0,3
10,105,10
5,205,50
0,0,0
```

115 kV Line Fair Weather:

1,0,3,5,115.0,2.00,0.00,5600.00
'ALL'
4.921,6.562,9.842,0.000,1.000,75.000,3.280,4.000,3.280
'PH.A-1','A',12.500,27.500,1,0.858,18.000,66.395,0.000,0.850,0.
'PH.B-1','A',0.000,27.500,1,0.858,18.000,66.395,-120.000,0.850,0.
'PH.C-1','A',-12.500,27.500,1,0.858,18.000,66.395,120.000,0.850,0.
'GND1-1','A',6.25,41.4,1,0.360,0.000,0.000,0.000,0.000,0.
'GND2-1','A',-6.25,41.4,1,0.360,0.000,0.000,0.000,0.000,0.
10,0,3
10,105,10
5,205,50
0,0,0

115 kV Line Foul Weather:

1,0,3,5,115.0,10.00,0.12,5600.00
'ALL'
4.921,6.562,9.842,0.000,1.000,75.000,3.280,4.000,3.280
'PH.A-1','A',12.500,27.500,1,0.858,18.000,66.395,0.000,0.850,0.
'PH.B-1','A',0.000,27.500,1,0.858,18.000,66.395,-120.000,0.850,0.
'PH.C-1','A',-12.500,27.500,1,0.858,18.000,66.395,120.000,0.850,0.
'GND1-1','A',6.25,41.4,1,0.360,0.000,0.000,0.000,0.000,0.
'GND2-1','A',-6.25,41.4,1,0.360,0.000,0.000,0.000,0.000,0.
10,0,3
10,105,10
5,205,50
0,0,0

ATTACHMENT F

PREPARED DIRECT TESTIMONY OF ROBERT C. SMITH

Exhibit No. TS-008

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tri-State Generation & Transmission Association, Inc.	))))	**Docket No. ER19-___-000**

PREPARED DIRECT TESTIMONY AND EXHIBITS
OF ROBERT C. SMITH
ON BEHALF OF
TRI-STATE GENERATION & TRANSMISSION ASSOCIATION, INC.

Revenue Requirement for Reactive Power Production Capability of the Tri-State Generators in the Western Interconnect

Ancillary Service Schedule 3 – Regulation and Frequency Response
Ancillary Service Schedule 4 – Energy Imbalance Service
Ancillary Service Schedule 5 – Spinning Reserve Service
Ancillary Service Schedule 6 – Supplemental Reserve Service

July 23, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

Exhibit No.	**Description**
TS-008	Prepared Direct Testimony of Robert C. Smith
TS-009	Testimony Experience of Robert C. Smith
TS-010	Development of Reactive Revenue Requirements for Tri-State Generators in the Western Area
TS-011	Development of Annual Carrying Charge Related to Reactive Based on the "*AEP Method*."
TS-012	Development of Fixed O&M Expense Allocable to Western Area Tri-State Units
TS-013	Allocation Factors for Use in Development of Reactive Related Production Plant Investment for Tri-State Facilities
TS-014	Generator and Exciter Investment
TS-015	Generator Step-Up Transformer Investment
TS-016	Accessory Electric Equipment Investment
TS-017	Tri-State Western Area Individual Plant Investment Detail
TS-018	Cost of Capital
TS-019	Allocation of Common Facilities at Craig and Laramie River Stations
TS-020	Depreciation Life
TS-021	Total Western Area Plant Investment Detail

Exhibit No.	Description
TS-022	Nameplate Pictures for the western-area units
TS-023	MOD-025-2 Test Reports and Capability Curves

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tri-State Generation & Transmission Association, Inc.	))))	**Docket No. ER19-___-000**

PREPARED DIRECT TESTIMONY AND EXHIBITS
OF ROBERT C. SMITH
ON BEHALF OF
TRI-STATE GENERATION & TRANSMISSION ASSOCIATION, INC.

I INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert C. Smith. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Vice President at GDS Associates, Inc. ("GDS"), a multi-disciplinary engineering and consulting firm that serves primarily electric, gas and water utilities. I have been with GDS since its founding in 1986.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I received a Bachelor of Science in Industrial Management degree from the Georgia Institute of Technology in 1982.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AT GDS ASSOCIATES?

A. My primary responsibilities involve providing rate and regulatory consulting services related to electric utility industry matters, including rate design, cost of service and related revenue requirements, Regional Transmission Organization ("RTO") membership, transmission revenue requirements and formula rates, and ancillary services.

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL EXPERIENTS.

A. I have been a consultant in the electric utility industry for my entire career, spanning approximately thirty-seven (37) years. I am also a senior member of the Institute of Electrical and Electronic Engineers. My primary responsibilities with GDS for the past thirty-three (33) years have involved assignments pertaining to wholesale rates, retail rates, financial planning, power supply planning for electric utilities, transmission access, electric industry restructuring, deregulation policy development and implementation, and interfacing with and operating under RTOs. Throughout my career, I have provided consulting services to dozens of electric cooperatives, municipal power systems, investor-owned utilities, utility customers, and various regulatory agencies across the United States. I have testified before the Federal Energy Regulatory Commission ("FERC" or the "Commission") as well as various state regulatory commissions. My responsibilities have included the preparation of allocated cost-of-service studies, retail and wholesale rate design studies, financial forecasts, revenue requirement evaluations, rate design, analyses of alternative power supply resources and testimony supporting the development of transmission ancillary service charges. These activities have also involved the review of cost of service, revenue requirements and transmission formulary rates

regulated by the Commission. I have been involved with RTO and non-RTO issues for a number of years related to formula rates.

Q. HAVE YOU HAD OCCASION TO PROVIDE CONSULTING SERVICES RELATED TO ELECTRIC UTILITY ALLOCATED COST OF SERVICE STUDIES AND REVENUE REQUIREMENCE?

A. Yes. Over the years, I have participated with many cost of service filings at the Commission. In addition, I have provided testimony on the appropriateness of cost of service studies in investor-owned utility rate cases at FERC where cost allocation and revenue requirements were at issue. I am familiar with electric utility cost allocation methods, GAAP Accounting, and FERC and National Association of Regulatory Utility Commissioners ("NARUC") general cost of service and ratemaking principles and the Uniform System of Accounts. During the past several years, my focus has been on FERC regulatory matters involving wholesale transmission rates and services. I have participated in numerous proceedings (both cost-of-service and formula rate cases) in which the proper level of transmission revenue requirements was at issue.

I've filed testimony at the Commission in approximately twenty (20) reactive (Schedule 2 ancillary) cases for applicants over the past ten years. I've also participated in proceedings at the Commission in a number of reactive filings by other entities on behalf of my customer clients.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes. A list of utility regulatory proceedings in which I have filed testimony is set forth in Exhibit No. TS-009.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am presenting this testimony on behalf of Tri-State Generation & Transmission Association, Inc. ("Tri-State").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss and support the cost-based revenue requirement for Tri-State's provision of reactive supply and voltage control service from its ownership in generating units interconnected with the Tri-State transmission system in the Western Interconnect (collectively, the "Facilities"). Following Commission acceptance of Tri-State's requested cost-based revenue requirement for the provision of reactive supply and voltage control service, Tri-State intends to take the necessary steps to charge transmission customers through Schedule 2 (Reactive Supply and Voltage Control from Generation or Other Sources) Service of the Tri-State Western OATT. Additionally, I describe Tri-State's proposed pass-through of costs to transmission customers using Ancillary Services 3, 4, 5 and 6.[1]

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[1] Ancillary Service Schedule 3 – Regulation and Frequency Response, Ancillary Service Schedule 4 – Energy Imbalance Service, Ancillary Service Schedule 5 – Spinning Reservice Service, Ancillary Service Schedule 6 – Supplemental Reserve Service

II ANCILLARY SERVICES 3, 4, 5 AND 6

Q. WHICH ANCILLARY SERVICES IS TRI-SATE AS THE TRANSMISSION PROVIDER, REQUIRED TO OFFER?

A. The Transmission Provider is required to offer to provide (or offer to arrange with the local Balancing Authority Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Balancing Authority Area(s) (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Spinning, (iv) Operating Reserve - Supplemental, and (v) Generator Imbalance. The Transmission Customer serving load within the Transmission Provider's Balancing Authority Area(s) is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

Q. IS TRI-SATE A "BALANCING AUTHORITY AREA" WHEREBY IT OFFERS REGULATION AND FREQUENCY SERVICE, ENERGY IMBALANCE SERVICE, SPINNING RESERVE SERVICE, AND SUPPLEMENTAL RESERVE SERVICE?

A. No, Tri-State as the Transmission Provider for its western system is not a Balancing Authority Area operator.

Q. HOW WILL TRI-STATE OFFER ANCILLARY SERVICES 3 THROUGH 6 TO TRANSMISSION CUSTOMERS ON ITS WESTERN SYSTEM?

A. Since Tri-State is not a Balancing Authority Area operator. The customer can either arrange for these ancillary services itself, or Tri-State will offer to arrange

for Ancillary Service Schedules 3 through 6 and will reflect only a pass-through of the costs charged to Tri-Sate by that Balancing Authority operator.

II.1 <u>ANCILLARY SERVICE SCHEDULE 2 – REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION OR OTHER SOURCES</u>

Q. HAS TRI-STATE PREVIOUSLY FILED ITS REACTIVE POWER REVENUE REQUIREMENT FOR ITS GENERATING UNITS CONNECTED TO ITS WESTERN TRANSMISSION SYSTEM?

A. No, it has not. Concurrently with this filing, Tri-State is making a number of submittals to the Commission that, among other things, results in Tri-State becoming a regulated Public Utility at this Commission for the first time.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY AT THE COMMISSION IN SUPPORT OF A SUPPLIER'S REVENUE REQUIREMENTS FOR ITS REACTIVE POWER PRODUCTION CAPABILITY?

A. Yes, I filed testimony and exhibits supporting a supplier's annual revenue requirements for reactive supply in the following proceedings: *Prairie Power, Inc.*, Docket No. EL11-16 ("*Prairie Power*"); *Hillman Power Company LLC*, Docket No. ER13-2076 ("*Hillman Power*"); *Lakewood Cogeneration, LP*, Docket ER14-199 ("*Lakewood*"); *East Texas Electric Cooperative, Inc. and Sam Rayburn G&T Electric Cooperative, Inc.*, Docket No. ER14-1458 ("*East Texas*"); *Homer City Generation LLP*, Docket No. ER14-2281 ("*Homer City*"); *Occidental Power Services, Inc*. Docket No. ER15-878 (*"Occidental"*); *Arkansas Electric Cooperative Corporation*, Docket No. ER15-953 ("*AECC"); City of Alexandria*,

Louisiana, Docket Nos. EL15-49 and EL17-80;; *The Empire District Electric Company*, Docket No. ER15-1405; *Municipal Energy Agency of Mississippi*, Docket No. NJ15-13; the *Missouri Joint Municipal Electric Utility Commission*, Docket No. EL16-26; *Old Dominion Electric Cooperative,* Docket No. ER17-2290; and the *City Water and Light Plant of the City of Jonesboro,* Docket No. EL18-36; *American Municipal Power, Inc.*, Docket No. EL18-172 ("*Cannelton Hydro*"); *American Municipal Power, Inc.*, Docket No. EL18-174 ("*Smithland Hydro*"); *American Municipal Power, Inc.*, Docket No. EL18-181 ("*Belleville Hydro*"); *Meldahl, LLC*, Docket No. EL18-184 ("*Meldahl Hydro*"); *American Municipal Power, Inc.*, Docket No. EL18-185 ("*Willow Island Hydro*") and *Tri-State,* Docket No. EL19-49. I've also filed testimony and exhibit in *Panda Stonewall LLC*, Docket No. ER17-1821-002 on behalf of customers in the PJM Dominion transmission zone.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes, in addition to TS-009, described above, I am sponsoring these additional exhibits:

TS-010	Development of Reactive Revenue Requirements for Tri-State Generators in the Western Area
TS-011	Development of Annual Carrying Charge Related to Reactive Based on the "AEP Method."
TS-012	Development of Fixed O&M Expense Allocable to Western Area Tri-State Units

TS-013 Allocation Factors for Use in Development of Reactive Related Production Plant Investment for Tri-State Facilities

TS-014 Generator and Exciter Investment

TS-015 Generator Step-Up Transformer Investment

TS-016 Accessory Electric Equipment Investment

TS-017 Tri-State Western Area Individual Plant Investment Detail

TS-018 Cost of Capital

TS-019 Allocation of Common Facilities at Craig and Laramie River Stations

TS-020 Depreciation Life

TS-021 Total Western Area Plant Investment Detail

TS-022 Nameplate Pictures for the western-area units

TS-023 MOD-025-2 Test Reports and Capability Curves

Q. WERE THESE EXHIBITS PREPARED EITHER BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

III SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. I was asked by Tri-State to prepare a cost of service study and supporting testimony to establish the cost-based revenue requirement and resulting rate for Tri-State's provision of reactive supply and voltage control service from its generating

facilities connected to the Tri-State Western Transmission System. To satisfy that directive, my testimony provides the following:

1. A specification of Tri-State's investment in plant components that have been recognized as contributing to a generating unit's reactive power production capability. These components, and the associated cost categories, are: (a) generators and exciters; (b) step-up transformers; (c) Accessory Electric Equipment; and (d) items of place not encompassed by the preceding three categories (referred to as "Balance of Plant");
2. An explanation of the allocation factors that would be applied to Tri-State's investment in each of these four categories of plant components in order to arrive at the amount of investment in each category that is associated with the reactive production capability;
3. A discussion of the application of the foregoing allocation factors to each such category of investment;
4. An explanation of the fixed charge rate that is to be applied to the allocated amounts of investment to calculate annual ownership, operating and maintenance costs; and
5. My calculation of the total annual revenue requirement (cost of service) and rate for the Facilities associated with the production of reactive power and voltage control service in the Western Interconnect.

Q. BASED ON YOUR ANALYSIS, WHAT IS TRI-STATE'S ANNUAL REVENUE REQUIREMENT FOR ITS WESTERN-AREA PRODUCTION CAPABILITY?

A. As shown in Exhibit No. TS-010, line 28, I calculate the cost-based annual revenue requirement for Tri-State's provision of reactive supply and voltage control service from its generating units connected to the Tri-State Transmission System in the Western Interconnect to be approximately $2.54 million. The resulting annual and monthly rate is $1,090.28/MW year and $90.86/MW Mo. for Ancillary Schedule 2 under Tri-State's western OATT as shown on lines 32 through 36.

IV BACKGROUND

I.1 DESCRIPTION OF TRI-STATE

Q. PLEASE DESCRIBE TRI-STATE.

A. Tri-State Generation and Transmission Association is a not-for-profit wholesale power supply association of 43 member electric cooperatives and public power districts in four states that together deliver power to more than a million rural electricity consumers across nearly 200,000 square miles of the western United States.

IV.2 DESCRIPTION OF TRI-STATE GENERATING UNITS CONNECTED TO THE TRI-STATE TRANSMISSION SYSTEM IN THE WESTERN INTERCONNECT

Q. PLEASE DESCRIBE THE FACILITIES.

A. Tri-State has seven (7) generating plants containing twenty-one (21) generating units connected to the Tri-State transmission system in the Western Interconnect. These Units are:

- Burlington Station (Burlington, Colorado) consisting of two 64.7 MW Gas Turbines. Tri-State owns 100% of Burlington.
- Craig Station Units 1, 2 and 3 (Craig, Colorado).Tri-State owns 107 MW of units 1 and 2 and 534 MW of unit 3 commensurate with Tri-State's 24% ownership share of Unit 1 and2 and 100 % of Unit 3
- Escalante Generating Station (Prewitt, New Mexico) consisting of a 257 MW Coal-fired Steam Turbine. Tri-State owns 100% of Escalante.
- Laramie River Station 2 & 3 (Wheatland, Wyoming) consisting of two 155 MW (Tri-States' ownership share) Coal-fired Steam Turbines. Tri-State owns 27.13% of each unit.
- Limon Generating Station units 1 and 2 consisting of two 77 MW natural gas generating units located in Lincoln, Colorado. Tri-State owns 100% of the Limon units.
- Pyramid Generating Station (Lordsburg, New Mexico) consisting of four (4) 45.6 MW Gas Turbines. Tri-State owns 100% of Pyramid. And;
- The J.M. Shafer Combined Cycle Generating Station (Fort Lupton, Colorado) consisting of five (5) 58.5 MW Gas Turbines and two (2) 52 MW heat recovery Steam Turbines. Tri-State owns 100% of the Safer units.

Q. DOES TRI-STATE OPERATE EACH OF THE FACILITIES?

A. Tri-State operates all the facilities at issue in this filing except Laramie River Station which is operated by Basin Electric Cooperative.

Q. PLEASE EXPLAIN WHAT REACTIVE POWER IS, HOW IT IS USED AND WHY IT IS NECESSARY.

A. The production of electric power in an alternating current power system consists of two parts: real power (measured in watts ("W")) and reactive power (measured in volt ampere reactive ("VAR")). Reactive power is supplied by both generators and static devices, such as capacitors, that are connected to the transmission system. Reactive power provides a stable voltage profile and is required to establish electric fields in facilities such as transmission lines and electric motors.

Q. WHAT IS THE PURPOSE OF SCHEDULE 2 (REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION OR OTHER SOURCES SERVICE) OF THE TRI-STATE TARIFF?

A. In order to keep operating voltages within acceptable limits on Tri-State's transmission facilities, various types of equipment are operated to produce or absorb reactive power. The costs of the equipment used for this purpose are treated as part of the cost of transmission service under the proposed Tri-State Western-area Tariff. Schedule 2 of the Tariff is the mechanism for recovering those costs from transmission customers. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to a Transmission Customer's transaction is determined by Tri-State (as the Transmission Provider) based on the reactive power support necessary to maintain transmission voltages within the voltage range and the resulting reactive power range that are generally accepted in the region and consistently adhered to by the Transmission Provider.

V CALCULATION OF TRI-STATE'S COST-BASED REVENUE REQUIREMENT

V.1 OVERVIEW OF THE REVENUE REQUIREMENT CALCULATION

Q. WHAT ARE THE PRIMARY COMPONENTS THAT MAKE UP TRI-STATE'S PROPOSED COST-BASED REVENUE REQUIREMENT FOR PROVIDING REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE FROM GENERATING UNITS?

A. A supplier's revenue requirement for reactive supply and voltage control service typically consists of two parts: (i) a Fixed Capability Component, which is designed to recover the supplier's ownership and operating costs of the above-listed four groups of facilities that contribute to providing the service; and (ii) a Heating Losses Component, which is intended to recover the supplier's costs associated with incremental generator and GSU heating losses that result from the production of reactive power, and may also include opportunity costs reflecting diminished sales of real power.

Q. WHAT COMPONENTS OF A GENERATING UNIT ARE ASSOCIATED WITH SUPPLYING REACTIVE POWER AND PROVIDING VOLTAGE CONTROL SERVICE?

A. As discussed earlier, there are four sets of components in generating plants that are associated with providing reactive supply and voltage control service. These are:

1. The generator and excitation system;
2. Generator step-up transformer ("GSU");

3. Accessory Electric Equipment; and
4. Remainder of investment or "Balance of Plant."

To determine the "Fixed Capability Component" of a supplier's reactive supply revenue requirement, the installed costs of each of the four sets of components are determined from accounting data and engineering estimates. Those installed costs then are allocated between the provision of reactive power and real power. The Fixed Capability Component of the revenue requirement multiplied by the Annual Fixed Charge rate for each unit represents the annual on-going ownership and operating costs of the facilities that contribute to providing the service.

Q. PLEASE DESCRIBE THE COMMISSION'S APPROVED METHODOLOGY FOR A GENERATION OWNER TO DEVELOP ITS REVENUE REQUIREMENTS FOR PROVIDING REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE.

A. The Commission established the currently approved method of pricing reactive power supply in *American Electric Power Service Corp.*, Opinion 440, 88 FERC ¶ 61,141 (1999), *order on reh'g*, 92 FERC ¶ 61,001 (2000) ("*AEP*"). In *AEP*, the Commission approved a method for American Electric Power to recover the costs of reactive power production that has come to be known as the "*AEP* Methodology." The *AEP* Methodology generally reflects the fixed costs associated with four groups of equipment: the generator-exciter system; the GSU; Accessory Electric Equipment; and Balance of Plant (any remaining production plant investment not encompassed within the preceding three categories of facilities). Because these groups of equipment are used in producing both real power and

reactive power, the *AEP* Methodology calls for the application of an allocation factor that properly distinguishes between these functions in isolating the revenue requirements associated solely with reactive power production.

Q. HOW IS THAT ALLOCATION FACTOR TO BE DETERMINED?

A. The Commission has found that the allocator that should be used to determine the amount of generator-exciter investment related to reactive power production is based on the ratio of $MVAR^2$ to MVA^2 (reactive allocator) where MVAR is megavolt amperes reactive capability and MVA is megavolt amperes capability at a power factor of one. Because GSUs also facilitate the transmission of real and reactive power, GSUs are allocated to reactive using the same allocator to determine the portion of GSU investment related to reactive power service. Accessory equipment – including such equipment as auxiliary generators, generator main connections and station buses – are allocated to reactive power production by determining the amount of investment in accessory equipment that is attributable to the generator/exciter and then allocating a portion of this investment to the provision of reactive service. The remaining production plant investment is calculated by subtracting the generator-exciter, GSU and accessory equipment investment from total production plant investment, to avoid double counting. The remaining production plant investment is allocated to reactive power service using the allocator called the "balance of plant allocator," which is the product of two ratios. The first ratio is Exciter MW/Generator MW while the second ratio is the Maximum MVARs/Nameplate MVARs.

Once the reactive power-related costs of the generator-exciter, the GSU, accessory electric equipment and Balance of Plant are identified, the sum of these (representing the total plant investment in reactive power capability) is multiplied by a fixed charge rate that reflects the supplier's annual cost of owning, operating and maintaining the reactive power investment in the plant.

Q. HAS THE *AEP* METHODOLOGY BEEN CLARIFIED AND REFINED IN SUBSEQUENT COMMISSION ORDERS?

A. Yes. The *AEP* Methodology has been applied numerous times since 1999-2000, and some of the orders applying that methodology have clarified its use. Notable orders in this vein include *Dynegy Midwest Generation, Inc.,* Opinion No. 498, 121 FERC ¶ 61,025 (2007), *order on reh'g,* 125 FERC ¶ 61,280 (2008) and *Chehalis Power Generating, L.P.,* 123 FERC ¶ 61,038 (2008).

Q. IS TRI-STATE SEEKING A HEATING LOSSES COMPONENT AS PART OF ITS COST-BASED REVENUE REQUIREMENT FOR PROVIDING REACTIVE SERVICE?

A. Not at this time; Tri-State reserves its right to amend its revenue requirement in a subsequent filing should it elect to seek compensation for heating losses in the future. Therefore, the revenue requirement submitted in this proceeding includes only the Fixed Capability Component.

Q. DOES TRI-STATE USE THE UNIFORM SYSTEM OF ACCOUNTS ("USOFA" OR "FERC ACCOUNTING")?

A. No. Tri-State is a cooperative. As such, it must use the RUS System of Accounts. However, the RUS System of Accounts is substantially similar to the FERC

Uniform System of Accounts. Upon becoming regulated by the FERC, Tri-State will use the USofA and file an annual FERC Form 1.

V.2 DETERMINATION OF THE PLANT INVESTMENT ALLOCABLE TO REACTIVE POWER PRODUCTION

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE AMOUNT OF PLANT INVESTMENT PROPERLY INCLUDED IN CALCULATING TRI-STATE'S REACTIVE REVENUE REQUIREMENT FOR THE FACILITIES.

A. The Fixed Capability Component of the revenue requirement represents the ongoing cost to own, operate and maintain that portion of Tri-State's total investment in the Facilities that is properly attributed to the units' capability to produce reactive power. For purposes of calculating the Fixed Capability Component, I determined the amount of Tri-State's investment properly included in calculating Tri-State's reactive revenue requirement through the following steps.

1. Tri-State provided investment data from their accounting records that allowed me to determine the amount of investment in the generator/exciter systems, the GSUs, and the Accessory Electric Equipment.
2. Tri-State provided me with its estimate of the percentage of investment in certain production accounts that is related to the generator and exciter based on engineering knowledge.
3. Because the turbine-generators contribute to the generation of both real and reactive power, I multiplied the total investment in generator/exciter system

by a reactive power allocation factor to determine the portion of the investment that is associated with the capability to produce reactive power.

4. I identified and allocated to the reactive revenue requirement an appropriate portion of the costs associated with Accessory Electric Equipment at the plant. Since seventy-five percent of Tri-State's capacity subject to this filing are coal units, I used the same Accessory allocator as in *AEP*.

5. I identified the Generator Step-Up Transformers from Tri-State's books and multiplied that investment by the reactive allocation factor.

6. I also identified and allocated to the reactive revenue requirement an appropriate portion of the costs associated with the Balance of Plant investment.

7. I summed the above amounts to arrive at the amount of total plant investment attributable to reactive power production.

Q. HOW DID YOU IDENTIFY THE COSTS ASSOCIATED WITH THE GENERATOR/EXCITER SYSTEMS, THE GSUS AND ACCESSORY ELECTRIC EQUIPMENT AT THE FACILITIES?

A. Plant investment details (detailed Asset records) for the units were provided to me by Tri-State from detailed accounting records. I then categorized each investment line item from the appropriate FERC Accounts for the generator/exciter system, GSU, and Accessory Electric Equipment where applicable as shown on Exhibit Nos. TS-014, 8, 9, 12 and 14.

Q. HOW DID YOU ESTIMATE THE GENERATOR/EXCITER INVESTMENT ATTRIBUTABLE TO EACH UNIT?

A. Detail necessary to identify investment in the generator/exciter systems at each facility was not readily available. Therefore, Tri-State engineers provided me with an estimate of generator/exciter percentage investment as a percentage of investment in the three FERC accounts 314, 343, and 344 based on the judgment of engineers on Tri-State's staff. The estimate of Tri-State's generator/exciter investment is equal to 8.73% of the total of these three Generation investment accounts.

Q. IN CALCULATING A SUPPLIER'S REACTIVE REVENUE REQUIREMENT, IS IT APPROPRIATE TO INCLUDE 100% OF THE SUPPLIER'S INVESTMENT IN AN ITEM OF EQUIPMENT USED IN GENERATING REACTIVE POWER?

A. No. Because the exciter and generator provide both real and reactive power, the AEP Methodology requires that the investment be allocated between these two functions, and only the reactive portion included in the revenue requirement calculation. This requires application of a Reactive Allocation Factor to the supplier's investment in the generator/exciter, GSU and Accessory Electric Equipment.

Q. PLEASE DESCRIBE HOW YOU CALCULATED THE REACTIVE POWER ALLOCATION FACTOR FOR THE WESTERN-AREA TRI-STATE GENERATING UNITS.

A. I developed Reactive Power Allocation Factors for each unit using the same methodology that has been accepted by the Commission in other OATT Schedule 2 filings. That methodology recognizes that generator investment is a function of

the total rated power in megavolt-amperes ("MVA"). Rated MVA is related to the rated real and reactive capabilities according to the following equation:

$$MVA_{Gen}^2 = MW_{Gen}^2 + MVAR_{Gen}^2$$

If both sides of the equation are divided by MVA_{Gen}^2 the resulting equation shows the shares of real and reactive power in a power generating facility:

$$100\% = \frac{MW_{Gen}{}^2}{MVA_{Gen}{}^2} + \frac{MVAR_{Gen}{}^2}{MVA_{Gen}{}^2}$$

Thus, pursuant to Commission precedent, the second term on the right-hand side of the equation, the ratio of $MVAR_{Gen}^2$ to MVA_{Gen}^2, is the percentage of applicable generating facility costs that is allocable to reactive power. As shown on Exhibit No. TS-013, I calculated the Tri-State Generator Allocation Factors to be between 8.8% and 27.75%, depending of generator nameplate data. The data that support the Real Power Capability, Design Power Factor, MVA Rated Capability along with "D" and capability curves of the Facilities are included as Exhibit No. TS-022.

Q. HOW DID YOU APPLY THE REACTIVE POWER ALLOCATION FACTOR?

A. I multiplied the Reactive Power Allocation Factor by the amount of investment attributable to each of the major categories of equipment – the generator/exciter system, the GSUs, and Accessory Electric Equipment for each Tri-State unit.

Q. IS A FURTHER ALLOCATION NECESSARY WITH RESPECT TO ACCESSORY ELECTRIC EQUIPMENT?

A. Yes. Because Accessory Electric Equipment performs functions associated with both the generator/exciter and the entire production plant, an Accessory Electric Equipment allocator must be applied. Pursuant to the *AEP* Methodology, a

percentage allocation for each type of Accessory Electric Equipment is determined based on engineering knowledge. Once the percentage allocation for a type of equipment is determined, the corresponding percentage of the cost of that equipment is allocated to reactive power production. The percentage of total Accessory Electric Equipment investment allocated to reactive power production is the Accessory Electric Equipment Allocator. The Accessory Electric Equipment Allocator I have used for the Facilities is 10.0% which is the allocator for Accessory Electric Equipment that was allowed in *AEP*. In *AEP* the majority of units studied were coal-fired units and here, the majority of Tri-State capacity at issue is also coal-fired, thus supporting the same allocation factor as in *AEP*.

Q. HOW DID YOU DETERMINE TRI-STATE'S INVESTMENT IN "BALANCE OF PLANT"?

A. The Balance of Plant investment at the Facilities is simply the total investment less the investments in the generator/exciter system, the GSU and Accessory Electric Equipment. My calculation of the Balance of Plant investment for each unit is also is shown on Exhibit No. TS-010, line 20.

Q. HOW DID YOU THEN DETERMINE THE PORTION OF TRI-STATE'S INVESTMENT IN BALANCE OF PLANT THAT IS ALLOCABLE TO THE PROVISION OF REACTIVE POWER AND VOLTAGE CONTROL SERVICE?

A. The total gross plant investment for each unit is shown on line 18 of Exhibit No. TS-010. As shown on the same exhibit, lines 19 and 20, I removed approximately $81.6 million for the Tri-State units as being associated with the generator/exciter,

GSUs, and the Accessory Electric Equipment that were allocated to the provision of reactive supply service in earlier calculations in Exhibit No. TS-017. The remaining balances of approximately $2.036 billion for the units was then allocated to reactive supply service using the "*AEP* Ratio" of 0.15%. The reactive power portion of the balance of plant investment was determined in *AEP* by multiplying the investment by the ratio of the maximum MVAR output of the utility fleet at the time of the system peak to the MVAR capability of the fleet, times the ratio of fleet exciter MW rating to the fleet generator rating. Given that all of this data is not readily available for these plants, I am using the balance of plant allocator of 0.15% which was found as reasonable in *AEP* and has been accepted by the Commission as a reasonable proxy for balance of plant in other reactive service filings.[2] Based on the *AEP* allocator, the amount of "Balance of Plant" investment allocated to reactive power production is $3.054 million in total for all of the Tri-State units at issue as shown on Exhibit No. TS-010, at line 22.

Q. PLEASE SUMMARIZE YOUR FINDINGS AS TO THE TOTAL AMOUNT OF ORIGINAL-COST PLANT INVESTMENT ATTRIBUTABLE TO REACTIVE POWER PRODUCTION FOR THE TRI-STATE FACILITIES.

A. Exhibit No. TS-010, line 24, shows the amount of total plant investment that is allocable to the Tri-State Facilities' reactive power production capability. As of December 31, 2018, that amount is $20.32 million.

[2] *See Prairie Power Inc.*, 135 FERC ¶ 61,025 (April 12, 2011); *Duke Energy Hanging Rock, LLC,* Docket No. ER05-567 (April 1, 2005) (unpublished letter order).

V.3 TESTED CAPABILITY OF THE FACILITIES

Q. THE REACTIVE POWER ALLOCATION FACTOR THAT YOU HAVE USED IS BASED ON GENERATOR NAMEPLATE DATA. IS THIS A REASONABLE APPROACH, GIVEN REACTIVE TESTING THAT HAS BEEN PERFORMED?

A. Yes. The MOD-025-2 test results for the Tri-State units is attached as Exhibit No. TS-023. The MOD-025-2 standard was developed to ensure that accurate information on generator gross and net, Real and Reactive power capabilities and synchronous condenser Reactive Power capability is available for (transmission) planning models used to asses Bulk Electric System reliability. Every Generator Owner is required to test every individual generating unit greater than 20 MVA and every generating plant/facility greater than 75 MVA every five years or within 12 months of the discovery of a change that affects it Real Power or Reactive Power capability by more than 10% of the last reported verified capability. The MOD-025-2 test results shown in Exhibit No. TS-023 substantially confirm the nameplate power factor capability of each unit and the use of nameplate data in the calculation of Reactive Power Allocation Factors.

Q. HAVE THE TRI-STATE UNITS AT ISSUE IN THIS FILING UNDERGONE MOD-025 TESTING?

A. Yes. All of the units have undergone NERC MOD-025 testing within the past three years. The test results shown in Exhibit No. TS-023 substantially confirm the nameplate power factor capability of the unit and the use of nameplate data in the calculation of Reactive Power Allocation Factors.

V.4 DETERMINATION OF TRI-STATE'S FIXED CHARGE RATE

Q. AFTER DETERMINING THE INVESTMENT ATTRIBUTABLE TO REACTIVE POWER PRODUCTION, WHAT IS THE NEXT STEP IN CALCULATING TRI-STATE'S COST-BASED REVENUE REQUIREMENT FOR PROVIDING REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE?

A. The next step is to develop an annual fixed charge rate that is applied to the total investment in reactive power production plants. This represents the annual cost to own, operate and maintain each unit (e.g. the annual Reactive Revenue Requirements)

Q. IS THERE COMMISSION GUIDANCE THAT YOU FOLLOWED IN APPROACHING THIS STEP?

A. Yes. In *WPS Westwood Generation, L.L.C.*, 101 FERC ¶ 61,290 (2002), the Commission recommended that all generators seeking reactive power cost recovery that have actual data and cost support utilize the method employed in *AEP*. Similar to other generators seeking reactive power compensation that has not previously been included in transmission rates, Tri-State utilizes a levelized annual carrying charge cost approach to develop its reactive revenue requirement.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE ANNUAL FIXED CHARGE RATE AND REVENUE REQUIREMENT ASSOCIATED WITH THE REACTIVE POWER PORTION OF INVESTMENT AT THE TRI-STATE GENERATING FACILITIES.

A. The levelized fixed charge rate used to determine the annual reactive revenue requirement contains the following components:

- O&M Expenses ("O&M")
- Administrative and General Expenses ("A&G")
- Property Taxes
- Property Insurance
- Working Capital (Materials & Supplies and Working Cash)
- Depreciation Expense (Sinking Fund)
- Return on Investment (Cost of Capital/Rate of Return)

Q. WHAT IS THE WEIGHTED OVERALL COST OF CAPITAL YOU USED IN DEVELOPING TRI-STATE'S ANNUAL FIXED CHARGE RATE?

A. In developing Tri-State's annual fixed charge rate, I used a weighted overall cost of capital of 6.10%. The calculation of this weighted cost of capital is shown in Exhibit No. TS-018 and is the same overall rate of return proposed by Tri-State in its Western transmission formula contained in this filing. The 6.10% overall capital cost rate is the combination of a 59.716% Long-Term Debt component with a debt cost rate of 4.49%, a 5.05% Notes Payable component with a cost rate of 2.76% and a 35.24% Equity Component at a base rate of return on equity of 9.30% (No RTO Adder). The overall rate of return is carried forward to Exhibit No. TS-011, line 16, as a component of Tri-State's annual fixed charge rate.

Q. WHAT IS THE SOURCE OF THE 6.10% WEIGHTED OVERALL COST OF CAPITAL?

A. As shown in Exhibit No. TS-018 and mentioned above, I have used the capital structure and cost rates of Tri-State from its proposed western area transmission formula included in this filing for the year ending 12/31/2018.

Q. WHAT ARE THE OTHER COMPONENTS OF A LEVELIZED ANNUAL FIXED CHARGE RATE?

A. The other components are fixed O&M expenses, A&G expenses, property taxes, insurance, depreciation, income taxes, and a working capital component.

Q. HOW DID YOU DETERMINE THE VALUE TO INCLUDE IN TRI-STATE'S LEVELIZED FIXED CHARGE RATE FOR O&M EXPENSE?

A. 2018 trial balance O&M schedules for the plants were provided to me by Tri-State which include an allocation of Tri-State internal A&G costs. These schedules contain operating expenses which I then classified as fixed or variable by using the FERC Predominance Method. The detail of fixed O&M expenses are shown on Exhibit No. TS-012.

Q. HOW DID YOU DETERMINE THE REMAINING COMPONENTS OF THE FIXED CHARGE RATE?

A. Because Tri-State is not subject to federal or state income taxation, the income tax component of Tri-State's fixed charge rate is zero. The depreciation component is calculated using the Commission's standard sinking fund method equal to return divided by the sum of one plus return to the n^{th} power minus one, where "n" equals the depreciable life of the plant $(R/(((1+R)^n)-1))$. Finally, the cash working capital component is calculated based on the Commission-accepted convention of one-eighth (1/8) of the sum of annual non-fuel O&M and A&G expense.

Q. WHAT IS THE ANNUAL FIXED CHARGE RATE FOR TRI-STATE YOU HAVE CALCULATED?

A. The detailed calculations of the Tri-State fixed charge rates are set forth in Exhibit No. TS-011 line 27.

Q. WHAT IS THE FINAL STEP IN DETERMINING THE FIXED CAPABILITY COMPONENT OF TRI-STATE'S REACTIVE REVENUE REQUIREMENT?

A. The final step is to apply the fixed charge rate to the total investment in reactive power production capability. This step is shown on Exhibit No. TS-010, lines 24 through 28.

Q. WHAT ARE THE RESULTS OF APPLYING TRI-STATE'S ANNUAL FIXED CHARGE RATES TO ITS TOTAL INVESTMENT IN REACTIVE POWER PRODUCTION CAPABILITY AT EACH OF THE FACILITIES?

A. As shown on Exhibit No. TS-010, when Tri-State's fixed charge rates are applied to the summation of the four components of Tri-State's reactive power investment at each unit, the resulting annual cost-based revenue requirement for Tri-State's provision of reactive supply and voltage control service is $2,543,530 annually. The resulting annual, monthly, weekly, daily, and hourly charge for Schedule 2 reactive is shown on Exhibit No. TS-010, lines 32 through 36.

I HAVE NO FURTHER QUESTIONS AT THIS TIME.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tri-State Generation and Transmission Association, Inc.	))))	**Docket No. ER19-___-000**

AFFIDAVIT OF ROBERT C. SMITH

Robert C. Smith, being first duly sworn, deposes and says that he is the Robert C. Smith referred to in the foregoing direct testimony, filed on behalf of Tri-State Generation and Transmission Association, Inc., that he has read such testimony, and is familiar with the contents thereof and that the answers therein are true and correct to the best of his knowledge, information, and belief.

Robert C. Smith

Subscribed and sworn to before me this 15th day of July, 2019, by Self, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

LISA D WILSON NOTARY PUBLIC EXP 01/08/2023 BARTOW COUNTY, GEORGIA

Notary Public

Commission Expires on: January 8, 2023

Tri-State Generation and Transmission Association
Docket No. ER19-_____
Proceedings in which direct testimony was filed by Robert C. Smith

Federal Energy Regulatory Commission

Gulf States Utilities Co., Docket No. ER84-568
Gulf States Utilities Co., Docket No. ER85-355
Carolina Power & Light Co., Docket No. EL91-28-000
Delmarva Power & Light Co., Docket No. ER93-96-000
East Texas Electric Cooperative, Inc., Docket No. ER95-1175-000
Detroit Edison Co., Docket No. OA96-78-000
East Texas Electric Cooperative, Inc., Docket No. ER96-485-000
International Transmission Company, Docket No. ER00-3295-003.
Entergy Services, Inc., Docket No. ER07-956
Wolverine Power Supply Cooperative, Inc. Triennial Market Analysis Update, Docket No. ER98-411
Wolverine Power Supply Cooperative, Inc., Docket No. ER04-132-000
Wolverine Power Supply Cooperative, Inc., Docket No. EL04-38-000
City of Anaheim, California, Docket No. EL05-131-000
Southern California Edison Company, Docket No. ER09-1534
Old Dominion Electric Cooperative Triennial Market Analysis Update, Docket No. ER97-4314-010
New Dominion Energy Cooperative Triennial Market Analysis Update, Docket No. ER05-20
TEC Trading, Inc. Triennial Market Analysis Update, Docket No. ER01-2783-000
Entergy Services, Inc., Docket No. ER07-956
City of Riverside, California, Docket No. EL09-52-000
City of Pasadena, California, Docket No. EL09-67
Prairie Power, Inc. Docket No. EL11-16
Wolverine Power Supply Cooperative, Inc., Docket No. ER11-3480-000
City of Anaheim, California, Docket No. ER11-3594
City of Banning, California, Docket No. ER11-3962
City of Riverside, California, Docket No. ER11-3984
City of Pasadena, California, Docket No. ER11-4375
City of Azusa, California, Docket No. ER12-489
City of Colton, California, Docket No. ER13-207
Public Service Company of New Mexico, Docket No. ER11-1915
PJM Interconnection, L.L.C., Docket No ER12-2177
PJM Interconnection, L.L.C., Docket No ER12-2183

Federal Energy Regulatory Commission Continued

EP Rock Springs, LLC, Docket No. ER13-488
Municipal Electric Utilities Association of New York v. Niagara Mohawk Power, Docket No. EL13-16
Hillman Power Company, L.L.C., Docket No ER13-2076
Lakewood Cogeneration LP, Docket No. ER14-199
City of Anaheim, et al. v. Trans Bay Cable LLC, Docket No. EL14-15 and ER13-2412
East Texas Electric Cooperative, Inc. et. al., Docket No. ER14-1458
East Texas Electric Cooperative, Inc. et. al, Complainants v. *Entergy Texas, Inc*. Respondent, Docket No. EL14-43-000
Homer City Generation, L.P., Docket No. ER14-2281
Occidental Power Services, Inc. Docket No. ER15-878
Arkansas Electric Cooperative Corporation, Docket No. ER15-953
PJM Interconnection L.L.C. and Old Dominion Electric Cooperative, Docket No. ER15-967
City of Alexandria, Louisiana, Docket No. EL15-49
East Texas Electric Cooperative, Inc., Docket No. EL15-54
The Empire District Electric Company, Docket No. ER15-1405
Midcontinent Independent System Operator, Inc., Cleco Power LLC, Docket No. ER15-1440
Municipal Energy Agency of Mississippi, Docket No. NJ15-13-000
PJM Interconnection L.L.C. and North Carolina Electric Membership Corporation, Docket No. ER15-1715
PJM Interconnection L.L.C. and Old Dominion Electric Cooperative, Docket No. ER15-1937
Southwest Power Pool, Inc., Docket No. ER15-1976
Southwest Power Pool, Inc., Docket No. ER15-2028
Southwest Power Pool, Inc., Docket No. ER15-2115
Midcontinent ISO and Prairie Power, Inc., Docket No. ER15-2364
Southwest Power Pool, Inc., Docket No. ER16-204
Southwest Power Pool, Inc., Docket No. ER16-209
Missouri Joint Municipal Electric Utility Commission, Docket No. EL16-26
Southwest Power Pool, Inc., Docket No. ER16-1054
Southwest Power Pool, *Inc.*, Docket No. ER16-1774
Midcontinent Independent System Operator, Inc., Docket No. ER15-277-005 and ER14-2154-006
East Texas Electric Cooperative, Inc., Docket No. EL17-14
East Texas Electric Cooperative, Inc., Docket No. EL17-92
City of Pasadena, California, Docket No. ER17-392
Southwest Power Pool, Inc., Docket No. ER17-1610
Southern Maryland Electric Cooperative, Inc., Docket No. ER17-1916
Pacific Gas & Electric Company, Docket No. ER16-2320-002
City of Alexandria, Louisiana, Docket No. EL17-80
PJM *Interconnection, L.L.C. and Old Dominion Electric Cooperative,* Docket No. ER17-2109
Old Dominion Electric Cooperative, Docket No. ER17-2290

Federal Energy Regulatory Commission Continued

City Water and Light Plant of the City of Jonesboro, Docket No. EL18-36
Southern Maryland Electric Cooperative, Inc., Docket No. ER18-963-000
American Municipal Power, Inc., Docket No. EL18-172 (Cannelton Hydro)
American Municipal Power, Inc., Docket No. EL18-174 (Smithland Hydro)
American Municipal Power, Inc., Docket No. EL18-181(Belleville Hydro)
Meldahl, LLC, Docket No. EL18-184 (Meldahl Hydro)
American Municipal Power, Inc., Docket No. EL18-185(Willow Island Hydro)
Panda Stonewall, L.L.C., Docket No ER17-1821-002
PJM Interconnection, L.L.C., Docket No. ER19-263
Southwest Power Pool, Inc., Docket No. ER19-456
Prairie Power Inc., Docket No. EL19-48
Cooperative Energy, Docket No. EL19-49
City of Pasadena, California, Docket No. ER19-1136

Public Utility Commission of Texas

Sam Rayburn G&T Electric Cooperative, Inc., Docket No. 6440
Sam Rayburn G&T Electric Cooperative, Inc., Docket No. 6797
Sam Rayburn G&T Electric Cooperative, Inc., Docket No. 7991
Sam Rayburn G&T Electric Cooperative, Inc., Docket No. 8595
Sam Rayburn G&T Electric Cooperative, Inc., Docket No. 9447
Sam Rayburn G&T Electric Cooperative, Inc., Docket No. 10982
Sam Rayburn G&T Electric Cooperative, Inc., Docket No. 12552
Sam Rayburn G&T Electric Cooperative, Inc., Docket No. 14893
Sam Rayburn G&T Electric Cooperative, Inc., Docket No. 16620
Tex-La Electric Cooperative of Texas, Inc., Docket No. 7279
Tex-La Electric Cooperative of Texas, Inc., Docket No. 10462
Tex-La Electric Cooperative of Texas, Inc., Docket No. 12289
Tex-La Electric Cooperative of Texas, Inc., Docket No. 12552
Tex-La Electric Cooperative of Texas, Inc., Docket No. 19875
Northeast Texas Electric Cooperative, Inc., Docket No. 11384
Northeast Texas Electric Cooperative, Inc., Docket No. 19642
East Texas Electric Cooperative, Inc., Docket No. 15133

Virginia State Corporation Commission

Appalachian Power Co., Case No. PUE900026
Appalachian Power Co., Case No. PUE2006-00065

Indiana Utility Regulatory Commission

Application of PSI Energy, Inc. Cause No. 38707-FAC50
Application of PSI Energy, Inc. Cause No. 38707-FAC67
Petition of Duke Energy Indiana, Inc., Cause No. 43955
Petition of Mishawaka Utilities, et.al, Cause No. 44080

Maryland Public Service Commission
Potomac Electric Power Company Case No. 9092
Southern Maryland Electric Cooperative Case No. 9456

Public Utilities Commission of Ohio
Monongahela Power Co. in Case No. 04-880-EL-UNC

District of Columbia Public Service Commission
Potomac Electric Power Company, Formal Case No. 1076.
Potomac Electric Power Company, Formal Case No. 1116.

The Regulatory Commission of Alaska
Matanuska Electric Association, Inc. - In the Matter of the Tariff Revision Designated as TA485-18, filed by for a Rate Revision and Rate Redesign.

Tri-State Generation and Transmission Association
Reactive Power Investment and Revenue Requirements
Docket No. EL19-____________

Line No (a)	Description (b)	Source (c)	Total Tri-State Western (d)	Burlington GT 1 (e)	Burlington GT 2 (f)	Craig ST 1 (g)	Craig ST 2 (h)	Craig ST 3 (i)	Escalante ST 1 (j)	Laramie River ST 2 (k)
1	**Generator and Exciter Equipment Costs**									
2	Total Generator/Exciter Costs	VAR-10	$ 49,753,431	$ 627,902	$ 627,902	$ 1,785,372	$ 2,097,547	$ 5,074,313	$ 7,528,579	$ 2,231,324
3										
4	**GSU Costs**									
5	Total GSU and Related Equipment Costs	VAR-10	$ 18,498,054	$ 327,854	$ 327,854	$ 563,249	$ 643,797	$ 3,411,661	$ 3,443,708	$ -
6										
7	**Accessory Electric Equipment**									
8	Total Accessory Electric Equipment	VAR-10	$ 133,529,862	$ 398,530	$ 398,530	$ 11,947,152	$ 12,583,268	$ 30,681,389	$ 41,606,530	$ 4,754,755
9	Accessory Electric Equipment Ratio	AEP Method		10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
10	Total Accessory Electric Equipment Allocated to the Generator Exciter	Line 8 * Line 9	$ 13,352,986	$ 39,853	$ 39,853	$ 1,194,715	$ 1,258,327	$ 3,068,139	$ 4,160,653	$ 475,476
11										
12	**Total Investment Allocated to Reactive Power Production**									
13	Total Cost of Generator/Exciter, GSU and Accessory Electric Equipment	Lines 2+5+10	$ 81,604,471	$ 995,608	$ 995,608	$ 3,543,337	$ 3,999,671	$ 11,554,113	$ 15,132,940	$ 2,706,799
14	Reactive Power Capability Allocator	VAR-6		19.00%	19.00%	19.00%	19.00%	8.80%	19.00%	19.00%
15	Total Portion of Costs Allocated to Support Reactive Power	Lnie 13 * Line 14	$ 17,264,634	$ 189,166	$ 189,166	$ 673,234	$ 759,938	$ 1,016,473	$ 2,875,259	$ 514,292
16										
17	**Remaining Production Plant**									
18	Total Production Plant Cost	Line 14	$ 2,118,204,291	$ 11,212,347	$ 11,212,347	$ 147,474,794	$ 146,546,722	$ 493,526,235	$ 562,370,313	$ 124,661,193
19	Less Generator/Exciter, GSU and Accessory Electric Equipment Costs	Line 13	$ 81,604,471	$ 995,608	$ 995,608	$ 3,543,337	$ 3,999,671	$ 11,554,113	$ 15,132,940	$ 2,706,799
20	Total Remaining Production Plant	Line 18 - Line 19	$ 2,036,599,820	$ 10,216,738	$ 10,216,738	$ 143,931,457	$ 142,547,051	$ 481,972,122	$ 547,237,374	$ 121,954,394
21	AEP Ratio	AEP Method	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
22	Total Remaining Production Plant used to support Reactive Power	Line 20 * Line 21	$ 3,054,900	$ 15,325	$ 15,325	$ 215,897	$ 213,821	$ 722,958	$ 820,856	$ 182,932
23										
24	**Total Investment Allocated to Reactive Production**	Line 15 + Line 22	$20,319,534	$204,491	$204,491	$889,131	$973,758	$1,739,431	$ 3,696,115	$ 697,223
25										
26	Annual Fixed Charge Rate	VAR-4		13.09%	13.09%	10.29%	10.88%	11.36%	10.66%	13.88%
27										
28	**Annual Reactive Revenue Requirement**	Line 24 * Line 26	$ 2,543,530	$ 26,759	$ 26,759	$ 91,464	$ 105,978	$ 197,558	$ 394,134	$ 96,796
29										
30	**Load Divisor (12-CP MW)**	Tri-State records	2,332.915	2,557.487	2,557.487	2,557.487	2,557.487	2,557.487	2,557.487	2,557.487
31										
32	Annual Charge ($/MW-year)	Line 28 / Line 30	$ 1,090.28	/MW/Yr						
33	Monthly Charge ($/MW-month)	Line 32 /12 mos.	$ 90.86	/MW/Mo						
34	Weekly Charge ($/MW-week)	Line 32 / 52 weeks	$ 20.97	/MW/wk						
35	Daily Charge ($/MW-day)	Line 32 / 365 days	$ 2.99	/MW/day						
36	Hourly Charge ($/MW-hour)	Line 35 / 16 hrs	$ 0.19	/MW/hour						

Tri-State Generation and Transmission Association
Reactive Power Investment and Revenue Requirements
Docket No. EL19-_____________

Laramie River ST 3 (l)	Limon GT 1 (m)	Limon GT 2 (n)	Pyramid GT 1 (o)	Pyramid GT 2 (p)	Pyramid GT 3 (q)	Pyramid GT 4 (r)	Shafer Thermo Fort Lupton LMA (s)	Shafer Thermo Fort Lupton LMB (t)	Shafer Thermo Fort Lupton LMC (u)	Shafer Thermo Fort Lupton LMD (v)	Shafer Thermo Fort Lupton LME (w)	Shafer Thermo Fort Lupton ST A (x)	Shafer Thermo Fort Lupton ST B (y)
$ 2,772,825	$ 2,432,648	$ 2,432,648	$ 2,053,666	$ 2,053,666	$ 2,053,666	$ 2,053,666	$ 2,084,972	$ 2,084,972	$ 2,084,972	$ 2,084,972	$ 2,084,972	$ 1,751,424	$ 1,751,424
$ -	$ 956,071	$ 956,071	$ 375,643	$ 375,643	$ 375,643	$ 375,643	$ 909,317	$ 909,317	$ 909,317	$ 909,317	$ 909,317	$ 909,317	$ 909,317
$ 7,163,530	$ 1,875,156	$ 1,875,156	$ 404,745	$ 404,745	$ 404,745	$ 404,745	$ 3,161,753	$ 3,161,753	$ 3,161,753	$ 3,161,753	$ 3,161,753	$ 1,409,060	$ 1,409,060
10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
$ 716,353	$ 187,516	$ 187,516	$ 40,474	$ 40,474	$ 40,474	$ 40,474	$ 316,175	$ 316,175	$ 316,175	$ 316,175	$ 316,175	$ 140,906	$ 140,906
$ 3,489,178	$ 3,576,235	$ 3,576,235	$ 2,469,784	$ 2,469,784	$ 2,469,784	$ 2,469,784	$ 3,310,464	$ 3,310,464	$ 3,310,464	$ 3,310,464	$ 3,310,464	$ 2,801,647	$ 2,801,647
19.00%	27.75%	27.75%	27.75%	27.75%	27.75%	27.75%	27.75%	27.75%	27.75%	27.75%	27.75%	19.00%	19.00%
$ 662,944	$ 992,405	$ 992,405	$ 685,365	$ 685,365	$ 685,365	$ 685,365	$ 918,654	$ 918,654	$ 918,654	$ 918,654	$ 918,654	$ 532,313	$ 532,313
$ 157,069,232	$ 38,134,725	$ 38,134,725	$ 27,004,073	$ 27,004,073	$ 27,004,073	$ 27,004,073	$ 39,977,910	$ 39,977,910	$ 39,977,910	$ 39,977,910	$ 39,977,910	$ 39,977,910	$ 39,977,910
$ 3,489,178	$ 3,576,235	$ 3,576,235	$ 2,469,784	$ 2,469,784	$ 2,469,784	$ 2,469,784	$ 3,310,464	$ 3,310,464	$ 3,310,464	$ 3,310,464	$ 3,310,464	$ 2,801,647	$ 2,801,647
$ 153,580,053	$ 34,558,490	$ 34,558,490	$ 24,534,289	$ 24,534,289	$ 24,534,289	$ 24,534,289	$ 36,667,446	$ 36,667,446	$ 36,667,446	$ 36,667,446	$ 36,667,446	$ 37,176,263	$ 37,176,263
0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
$ 230,370	$ 51,838	$ 51,838	$ 36,801	$ 36,801	$ 36,801	$ 36,801	$ 55,001	$ 55,001	$ 55,001	$ 55,001	$ 55,001	$ 55,764	$ 55,764
$ 893,314	$ 1,044,243	$ 1,044,243	$ 722,166	$ 722,166	$ 722,166	$ 722,166	$ 973,655	$ 973,655	$ 973,655	$ 973,655	$ 973,655	$ 588,077	$ 588,077
12.31%	11.57%	11.57%	9.46%	9.46%	9.46%	9.46%	16.56%	16.56%	16.56%	16.56%	16.56%	14.70%	14.70%
$ 110,001	$ 120,866	$ 120,866	$ 68,312	$ 68,312	$ 68,312	$ 68,312	$ 161,252	$ 161,252	$ 161,252	$ 161,252	$ 161,252	$ 86,421	$ 86,421
2,557.487	2,557.487	2,557.487	2,557.487	2,557.487	2,557.487	2,557.487	2,557.487	2,557.487	2,557.487	2,557.487	2,557.487	2,557.487	2,557.487

Tri-State Generation and Transmission Association
Docket No. EL19- ___________
Reactive Revenue Requirements and Rate
Development of Annual Carrying Charge

Line No. (a)	Item (b)	Source (c)	Total Tri-State Western Area (d)	Burlington GT 1 (e)	Burlington GT 2 (f)	Craig ST 1 (g)	Craig ST 2 (h)	Craig ST 3 (l)	Escalante ST 1 (m)	Laramie River ST 2 (n)
1	Total Cost of Production Plant	VAR-14	$ 2,118,204,291	$ 11,212,347	$ 11,212,347	$ 147,474,794	$ 146,546,722	$ 493,526,235	$ 562,370,313	$ 124,661,193
2										
3	Fixed O&M Expenses	VAR-5	$ 101,064,129	$ 652,040	$ 652,040	$ 4,379,191	$ 4,729,068	$ 20,400,579	$ 21,753,482	$ 8,966,574
4	Fixed O&M Expense Rate			5.82%	5.82%	2.97%	3.23%	4.13%	3.87%	7.19%
5										
6	Property Taxes	TS Records	$ 11,480,332	$ 88,521	$ 88,521	$ 866,367	$ 1,216,093	$ 3,864,963	$ 2,348,774	$ 445,941
7	Property Tax Rate			0.79%	0.79%	0.59%	0.83%	0.78%	0.42%	0.36%
8										
9	Property Insurance	TS Records	$ 2,980,675	$ 17,818	$ 17,818	$ 633,527	$ 768,152	$ 649,365	$ 395,955	$ -
10	Property Insurance Rate			0.16%	0.16%	0.43%	0.52%	0.13%	0.07%	0.00%
11										
12	Depreciable Life	TS Depreciation Study		60.0	60.0	60.0	60.0	60.0	60.0	60.0
13	SLDp = 1/Depreciable Years			1.67%	1.67%	1.67%	1.67%	1.67%	1.67%	1.67%
14										
15	SFDp = $(R/(((1+R)^n)-1))$ - Sinking Fund Depreciation	Calc		0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%
16										
17	Income Tax Expense - Tri-State is not Taxable									
18										
19	Overall Rate Of Return = R	VAR-11	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%
20										
21	Cash Working Capital Charge									
22	O&M and A&G	Line 3	$ 101,064,129	$ 652,040	$ 652,040	$ 4,379,191	$ 4,729,068	$ 20,400,579	$ 21,753,482	$ 8,966,574
23	1/8 O&M and A&G	Line 19 / 8	$ 12,633,016	$ 81,505	$ 81,505	$ 547,399	$ 591,133	$ 2,550,072	$ 2,719,185	$ 1,120,822
24	Return and Taxes on 1/8th	Line 16 * Line 20	$ 770,321	$ 4,970	$ 4,970	$ 33,379	$ 36,045	$ 155,495	$ 165,807	$ 68,344
25	Cash Working Capital Charge	Line 21 / Line 1		0.04%	0.04%	0.02%	0.02%	0.03%	0.03%	0.05%
26										
27	Total Annual Fixed Charge Rate	Line 4+7+12+16+22		13.09%	13.09%	10.29%	10.88%	11.36%	10.66%	13.88%

Tri-State Generation and Transmission Association
Docket No. EL19- ___________
Reactive Revenue Requirements and Rate
Development of Annual Carrying Charge

Laramie River ST 3 (o)	Limon GT 1 (p)	Limon GT 2 (u)	Pyramid GT 1 (v)	Pyramid GT 2 (w)	Pyramid GT 3 (x)	Pyramid GT 4 (ad)	Shafer Thermo Fort Lupton LMA (ae)	Shafer Thermo Fort Lupton LMB (af)	Shafer Thermo Fort Lupton LMC (ag)	Shafer Thermo Fort Lupton LMD (ah)	Shafer Thermo Fort Lupton LME (ai)	Shafer Thermo Fort Lupton ST A (aj)	Shafer Thermo Fort Lupton ST B (ak)
$ 157,069,232	$ 38,134,725	$ 38,134,725	$ 27,004,073	$ 27,004,073	$ 27,004,073	$ 27,004,073	$ 39,977,910	$ 39,977,910	$ 39,977,910	$ 39,977,910	$ 39,977,910	$ 39,977,910	$ 39,977,910
$ 8,966,574	$ 1,579,953	$ 1,579,953	$ 632,394	$ 632,394	$ 632,394	$ 632,394	$ 3,729,171	$ 3,729,171	$ 3,729,171	$ 3,729,171	$ 3,729,171	$ 3,114,623	$ 3,114,623
5.71%	4.14%	4.14%	2.34%	2.34%	2.34%	2.34%	9.33%	9.33%	9.33%	9.33%	9.33%	7.79%	7.79%
$ 445,941	$ 297,424	$ 297,424	$ 128,801	$ 128,801	$ 128,801	$ 128,801	$ 143,594	$ 143,594	$ 143,594	$ 143,594	$ 143,594	$ 143,594	$ 143,594
0.28%	0.78%	0.78%	0.48%	0.48%	0.48%	0.48%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%
$ -	$ 35,636	$ 35,636	$ 23,757	$ 23,757	$ 23,757	$ 23,757	$ 47,391	$ 47,391	$ 47,391	$ 47,391	$ 47,391	$ 47,391	$ 47,391
0.00%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%
60.0	46.0	46.0	45.7	45.7	45.7	45.7	41.1	41.1	41.1	41.1	41.1	53.4	53.4
1.67%	2.17%	2.17%	2.19%	2.19%	2.19%	2.19%	2.43%	2.43%	2.43%	2.43%	2.43%	1.87%	1.87%
0.18%	0.43%	0.43%	0.44%	0.44%	0.44%	0.44%	0.59%	0.59%	0.59%	0.59%	0.59%	0.27%	0.27%
6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%	6.10%
$ 8,966,574	$ 1,579,953	$ 1,579,953	$ 632,394	$ 632,394	$ 632,394	$ 632,394	$ 3,729,171	$ 3,729,171	$ 3,729,171	$ 3,729,171	$ 3,729,171	$ 3,114,623	$ 3,114,623
$ 1,120,822	$ 197,494	$ 197,494	$ 79,049	$ 79,049	$ 79,049	$ 79,049	$ 466,146	$ 466,146	$ 466,146	$ 466,146	$ 466,146	$ 389,328	$ 389,328
$ 68,344	$ 12,043	$ 12,043	$ 4,820	$ 4,820	$ 4,820	$ 4,820	$ 28,424	$ 28,424	$ 28,424	$ 28,424	$ 28,424	$ 23,740	$ 23,740
0.04%	0.03%	0.03%	0.02%	0.02%	0.02%	0.02%	0.07%	0.07%	0.07%	0.07%	0.07%	0.06%	0.06%
12.31%	11.57%	11.57%	9.46%	9.46%	9.46%	9.46%	16.56%	16.56%	16.56%	16.56%	16.56%	14.70%	14.70%

Exhibit No. TS-012

Tri-State Generation and Transmission Association
Docket No. EL19-____
Fixed O&M Expense Detail[1]

Line No. (a)	FERC Account (b)	2018 Expense (c)	Demand Related According to FERC Predominance Method (d)	Demand Related Expenses Only (e)
	JM Schafer			
1	500	990,617	Yes	990,617
2	501	15,508		
3	502	496,980	Yes	496,980
4	505	3,145,877	Yes	3,145,877
5	506	979,745	Yes	979,745
6	507	2,047	Yes	2,047
7	510	372,928		
8	511	352,143	Yes	352,143
9	512	46,746		
10	513	3,913,751		
11	514	261,838	Yes	261,838
	Total Steam	10,578,181		6,229,247
12	546	31	Yes	31
13	548	743,716	Yes	743,716
14	549	100,253	Yes	100,253
15	553	3,271,659	Yes	3,271,659
	Total Other	4,115,660		4,115,660
16	**Grand Total**	**14,693,841**		**10,344,907**
17				
18	**Escalante**			
19	500	3,975,921	Yes	3,975,921
20	501	30,720,176		
21	502	9,697,630	Yes	9,697,630
22	505	1,986,245	Yes	1,986,245
23	506	3,960,226	Yes	3,960,226
24	510	4,359,066		
25	511	892,022	Yes	892,022
26	512	6,455,468		
27	513	1,718,230		
28	514	1,241,437	Yes	1,241,437
29	**Total**	**65,006,421**		**21,753,482**
30				
31	**Burlington CT**			
32	546	285,387	Yes	285,387
33	547	788,443		
34	548	252,912	Yes	252,912
35	549	53,370	Yes	53,370

Exhibit No. TS-012

Tri-State Generation and Transmission Association
Docket No. EL19-____
Fixed O&M Expense Detail[1]

Line No. (a)	FERC Account (b)	2018 Expense (c)	Demand Related According to FERC Predominance Method (d)	Demand Related Expenses Only (e)
36	551	113,965	Yes	113,965
37	552	25,359	Yes	25,359
38	553	491,597	Yes	491,597
39	554	81,490	Yes	81,490
40	**Total**	**2,092,523**		**1,304,080**
41				
42	**Craig Unit 1 (Tri-State's Share)**			
43	500	307,458	Yes	307,458
44	501	16,377,719		
45	502	1,918,836	Yes	1,918,836
46	505	772,831	Yes	772,831
47	506	551,402	Yes	551,402
48	507	2,756	Yes	2,756
49	510	609,369		
50	511	297,222	Yes	297,222
51	512	1,590,391		
52	513	241,482		
53	514	528,686	Yes	528,686
54	556	17,235		
55	**Total**	**23,215,387**		**4,379,191**
56				
57	**Craig Unit 2 (Tri-State's Share)**			
58	500	300,236	Yes	300,236
59	501	17,574,739		
60	502	2,288,497	Yes	2,288,497
61	505	900,121	Yes	900,121
62	506	554,964	Yes	554,964
63	507	2,756	Yes	2,756
64	510	603,443		
65	511	289,215	Yes	289,215
66	512	1,632,804		
67	513	362,741		
68	514	393,278	Yes	393,278
69	556	17,235		
70	**Total**	**24,920,030**		**4,729,068**
71				
72	**Craig Unit 3**			
73	500	1,232,666	Yes	1,232,666
74	501	47,542,545		

Exhibit No. TS-012

Tri-State Generation and Transmission Association
Docket No. EL19-____
Fixed O&M Expense Detail[1]

Line No. (a)	FERC Account (b)	2018 Expense (c)	Demand Related According to FERC Predominance Method (d)	Demand Related Expenses Only (e)
75	502	10,216,880	Yes	10,216,880
76	505	2,788,416	Yes	2,788,416
77	506	2,571,564	Yes	2,571,564
78	507	11,480	Yes	11,480
79	510	2,797,353		
80	511	1,747,617	Yes	1,747,617
81	512	14,698,929		
82	513	5,160,511		
83	514	1,831,956	Yes	1,831,956
84	**Total**	**90,599,917**		**20,400,579**
85				
86	**Limon**			
87	546	448,704	Yes	448,704
88	547	1,568,301		
89	548	794,006	Yes	794,006
90	549	116,440	Yes	116,440
91	551	117,170	Yes	117,170
92	552	54,554	Yes	54,554
93	553	1,509,822	Yes	1,509,822
94	554	119,208	Yes	119,208
95	**Total**	**4,728,206**		**3,159,905**
96				
97	**Pyramid**			
98	546	419,077	Yes	419,077
99	547	2,698,473		
100	548	740,191	Yes	740,191
101	549	112,952	Yes	112,952
102	551	114,010	Yes	114,010
103	552	46,652	Yes	46,652
104	553	961,149	Yes	961,149
105	554	135,543	Yes	135,543
106	**Total**	**5,228,047**		**2,529,574**
107				
108	**Laramie River Station**			
109	500	5,649,802	Yes	5,649,802
110	501	37,825,874		
111	502	5,790,278	Yes	5,790,278
112	505	2,509,416	Yes	2,509,416
113	506	1,983,275	Yes	1,983,275

Exhibit No. TS-012

Tri-State Generation and Transmission Association
Docket No. EL19-____
Fixed O&M Expense Detail[1]

Line No.	FERC Account	2018 Expense	Demand Related According to FERC Predominance Method	Demand Related Expenses Only	
(a)	(b)	(c)	(d)	(e)	
114	510	4,148,852			
115	511	2,000,198	Yes	2,000,198	
116	512	11,139,137			
117	513	2,701,952			
118	514	179	Yes	179	
119	556	175,679			
120	560	534,614			Transmission
121	562	258,471			Transmission
122	563	199,715			Transmission
123	565	534,039			Transmission
124	566	224,579			Transmission
125	570	140,955			Transmission
126	571	61,798			Transmission
127	573	106,208			Transmission
128	**Total**	**75,985,021**		**17,933,148**	
129					
130	**Additional J.M. Schafer costs**				
131	547	12,881,670			
132	548	49,477	Yes	49,477	
133	550	14,480,718	Yes	14,480,718	
134	**Total**	27,411,864		14,530,195	
135	Grand Total	333,881,257		101,064,129	

Note 1: Tri-State allocates A&G expense to O&M Accounts. Thus, A&G expense is not shown separately

Exhibit No. TS-013

Tri-State Generation and Transmission Association
Docket No. EL19-_______
Reactive Power Allocation Factors

Line No. (a)	Unit (b)	Fuel Type (b1)	Rated Capability (MVA) (c)	Rated Power Factor (d)	Reactive Allocation Factor $1-(d)^2$ (e)
1	Burlington Unit #1	Fuel Oil	71.9	0.900	19.00%
2	Burlington Unit #2	Fuel Oil	71.9	0.900	19.00%
3	Craig Unit #1	Coal	496.0	0.900	19.00%
4	Craig Unit #2	Coal	496.0	0.900	19.00%
5	Craig Unit #3	Coal	560.0	0.955	8.80%
6	Escalante	Coal	285.6	0.900	19.00%
7	JM Shafer GTA	CC - Natural Gas	57.4	0.850	27.75%
8	JM Shafer GTB	CC - Natural Gas	57.4	0.850	27.75%
9	JM Shafer GTC	CC - Natural Gas	57.4	0.850	27.75%
10	JM Shafer GTD	CC - Natural Gas	57.4	0.850	27.75%
11	JM Shafer GTE	CC - Natural Gas	57.4	0.850	27.75%
12	JM Shafer STA	CC - Natural Gas	52.2	0.900	19.00%
13	JM Shafer STB	CC - Natural Gas	52.2	0.900	19.00%
14	Limon Unit #1	Natural Gas	90.8	0.850	27.75%
15	Limon Unit #2	Natural Gas	90.8	0.850	27.75%
17	LRS Unit #2	Coal	690.0	0.900	19.00%
18	LRS Unit #3	Coal	690.0	0.900	19.00%
19	Pyramid Unit #1	Natural Gas	71.2	0.850	27.75%
20	Pyramid Unit #2	Natural Gas	71.2	0.850	27.75%
21	Pyramid Unit #3	Natural Gas	71.2	0.850	27.75%
22	Pyramid Unit #4	Natural Gas	71.2	0.850	27.75%
23					
24	Fuel Oil		143.8	3%	
25	Natural Gas		857.8	20%	
26	Coal		3217.6	76%	
27	Totals		4219.2	100%	

Exhibit No. TS-014

Tri-State Generation and Transmission Association
Docket No. EL19-_______
Generator and Exciter Investment

Line No.	Facility No. Name	FERC REA	Gross Cost At 12/31/2018	Western Units	8.73% of Western Units
(a)	(b)	(c)	(d)	(e)	(f)
					8.73%
1	22 Total - Rifle				
2	23	314	86,238,014		
3	23 Total - Escalante		86,238,014	86,238,014	7,528,579
4	26	314			
5	26 Total - Nucla				
6	29	343	11,698,404		
7	29	344	2,686,511		
8	29 Total - Burlington		14,384,914	14,384,914	1,255,803
9	31	314	15,614,381		
10	31 Total - Craig 1		15,614,381	15,614,381	1,363,135
11	32	314	19,190,263		
12	32 Total - Craig 2		19,190,263	19,190,263	1,675,310
13	33	314	54,331,676		
14	33 Total - Craig 3		54,331,676	54,331,676	4,743,155
15	35	314	11,379,990		
16	35 Total - Craig 123 Common		11,379,990	11,379,990	993,473
17	37	314	2,086,581		
18	37 Total - Carig 1&2 common		2,086,581	2,086,581	182,159
19	47	314			
20	47 Total - Springerville				
21	70	343	55,713,942		
22	70	344	16,833		
23	70 Total - Limon		55,730,775	55,730,775	4,865,297
24	71	343			
25	71	344			
26	71 Total - Knutson		-		
27	72	343	94,008,780		
28	72	344	88,167		
29	72 Total - Pyramid		94,096,947	94,096,947	8,214,664
30	81	314	40,124,266		
31	81	343	98,399,943		
32	81	344	21,014,246		
33	81 Total - Shafer		159,538,455	159,538,455	13,927,707
34	91	314	29,222,428		
35	91 Total - LRS - 1		29,222,428		
36	92	314	23,536,622		
37	92 Total - LRS - 2		23,536,622	23,536,622	2,054,747

Exhibit No. TS-014

Tri-State Generation and Transmission Association
Docket No. EL19-_______
Generator and Exciter Investment

Line No.	Facility No. Name	FERC REA	Gross Cost At 12/31/2018	Western Units	8.73% of Western Units
(a)	(b)	(c)	(d)	(e)	(f)
					8.73%
38	93	314	29,739,386		
39	93 Total - LRS - -3		29,739,386	29,739,386	2,596,248
40	94	314	4,045,288		
41	94 Total - LRS -Common		4,045,288	4,045,288	353,154
42					
43	Total Western Units			569,913,294	49,753,431
44					
45	*According to the Generation Engineering Manager, Tri-State should use 8.73% of the 343 + 344 + 314 to reflect the Generator and Exciter portion of the investment. This percentage was determined based off various knowledge within the industry.				

Exhibit No. TS-015

Tri-State Generation and Transmission Association
Docket No. EL19-_______
Generator Step-Up Transformers

Line No. (a)	Power Station (b)	REA FAC (c)	Transformer Name (d)	Voltage kV (e)	Year End Investment $ (f)	Total $ (g)
1	Burlington	1611	Unit #1	13.8 / 115	327,854	327,854
2	Burlington	1611	Unit #2	13.8 / 115	327,854	327,854
3		Total Burlington			655,708	655,708
4						
5	Craig	31	1A	21 / 230	159,770	159,770
6	Craig	31	1B	21 / 230	159,770	159,770
7	Craig	31	1C	21 / 230	159,770	159,770
8	Craig	32	2A	21 / 230	136,958	136,958
9	Craig	37	2B	21 / 230	255,018	255,018
10	Craig	37	Spare #1&2	21 / 230	167,881	167,881
11	Craig	32	2C	21 / 230	167,881	167,881
12	Craig	33	3A	21 / 230	852,915	852,915
13	Craig	33	3B	21 / 230	852,915	852,915
14	Craig	33	3C	21 / 230	852,915	852,915
15	Craig	33	Spare #3	21 / 230	852,915	852,915
16		Total Craig			4,618,708	4,618,708
17						
18	JM Shafer	0081		13.8 / 230	1,014,894	1,014,894
19	JM Shafer	0081		13.8 / 230	1,014,894	1,014,894
20	JM Shafer	0081		13.8 / 230	1,014,894	1,014,894
21	JM Shafer	0081		13.8 / 230	1,014,894	1,014,894
22	JM Shafer	0081		13.8 / 230	1,014,894	1,014,894
23	JM Shafer	0081	Spare	13.8 / 230	1,290,746	1,290,746
24		Total JMS			6,365,217	6,365,217
25						
18	Knutson					
19	Knutson					
20		Total Knutson				
21						
22	Limon	0070	Unit #1	13.8 / 230	956,071	956,071
23	Limon	0070	Unit #2	13.8 / 230	956,071	956,071
24		Total Limon			1,912,142	1,912,142
25						
26	Nucla					
27	Nucla					
28	Nucla					
29	Nucla					
30	Nucla					
31		Total Nucla				
32						
33	Springerville					
34	Springerville					
35		Total Springerville				
36						
37	Escalante	0023	GSU	17.55 / 230	1,913,964	1,913,964
38	Escalante	0023	Spare	17.55 / 230	1,529,744	1,529,744
39		Total PEGS			3,443,708	3,443,708
40						
41	Pyramid	2040	Unit 1&2	13.8 / 115	751,286	751,286
42	Pyramid	2040	Unit 3&4	13.8 / 115	751,286	751,286
43		Total Pyramid			1,502,573	1,502,573
44						
45	Rifle					
46		Total Rifle				
47						
48	Total Generator Step-up Transformers				**18,498,054**	**18,498,054**
	Western Area Units					**18,498,054**

Exhibit No. TS-016

Tri-State Generation and Transmission Association
Docket No. EL19-_______
Accessory Equipment Investment

Line No.	FACILITY No. Name	FERC REA	Gross Cost At 12/31/2018	Western Units
(a)	(b)	(c)	(d)	(e)
1	22	315		
2	22	345		
3	22 Total - Rifle		-	
4	23	315	41,606,529.53	
5	23 Total - Escalante		41,606,529.53	41,606,530
6	26	315		
7	26 Total - Nucla			
8	29	345	797,060.55	
9	29 Total - Burlington		797,060.55	797,061
10	31	315	9,360,289.40	
11	31 Total - Craig 1		9,360,289.40	9,360,289
12	32	315	9,996,405.13	
13	32 Total - Craig 2		9,996,405.13	9,996,405
14	33	315	30,152,394.25	
15	33 Total - Craig 3		30,152,394.25	30,152,394
16	35	315	1,586,985.60	
17	35 Total - Craig 123 Common		1,586,985.60	1,586,986
18	37	315	4,115,734.59	
19	37 Total - Carig 1&2 common		4,115,734.59	4,115,735
20	38	315	446,580.13	
21	38 Total - Craig Coal Handling		446,580.13	446,580
22	47	315		
23	47 Total - Springerville			
24	70	345	3,750,312.28	
25	70 Total - Limon		3,750,312.28	3,750,312
26	71	345		
27	71 Total - Knutson		-	
28	72	345	1,618,978.92	
29	72 Total - Pyramid		1,618,978.92	1,618,979
30	81	315	2,818,120.84	
31	81	345	15,808,765.96	

Exhibit No. TS-016

Tri-State Generation and Transmission Association
Docket No. EL19-_______
Accessory Equipment Investment

Line No.	FACILITY No. Name	FERC REA	Gross Cost At 12/31/2018	Western Units
(a)	(b)	(c)	(d)	(e)
32	81 Total - Shafer		18,626,886.80	18,626,887
33	91	315	2,699,213.06	
34	91 Total - LRS - 1		2,699,213.06	
35	92	315	3,673,010.27	
36	92 Total - LRS - 2		3,673,010.27	3,673,010
37	93	315	6,081,785.09	
38	93 Total - LRS - -3		6,081,785.09	6,081,785
39	94	315	2,163,489.67	
40	94 Total - LRS - Common		2,163,489.67	2,163,490
41				
42	Total Western Units			133,976,442

Tri-State Generation and Transmission Association
Docket No. EL19-_______
Investment Detail of Reactive Components for Western Units

Line No. (a)	Description (b)	Total Tri-State Western Area (c)	Burlington GT 1 (d)	Burlington GT 2 (e)	Craig ST 1 (f)	Craig ST 2 (g)	Craig ST 3 (h)	Craig 1, 2 & 3 Common (i)	Craig 1 & 2 Common (j)	Craig Coal Handle (k)	Escalante ST 1 (l)	Laramie River ST 2 (m)
	Facility Number		29	29	31	32	33	35	37	38	23	92
1	Generators - Original Cost											
2	Account 314	$ 286,286,468			$ 15,614,381	$ 19,190,263	$ 54,331,676	$ 11,379,990	$ 2,086,581	$ -	$ 86,238,014	$ 23,536,622
3	Account 343	$ 259,821,069	$ 5,849,202	$ 5,849,202								
4	Account 344	$ 23,805,757	$ 1,343,255	$ 1,343,255								
5	Total By Unit	$ 569,913,294	$ 7,192,457	$ 7,192,457	$ 15,614,381	$ 19,190,263	$ 54,331,676	$ 11,379,990	$ 2,086,581	$ -	$ 86,238,014	$ 23,536,622
6	Tri-State Estimate of Gen/Exciter Cost		8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
7	Generator and Exciter Cost	$ 49,753,431	$ 627,902	$ 627,902	$ 1,363,135	$ 1,675,310	$ 4,743,155	$ 993,473	$ 182,159	$ -	$ 7,528,579	$ 2,054,747
7												
8	Accessory Electric Equipment											
8	315	$ 113,173,723			$ 9,360,289	$ 9,996,405	$ 30,152,394	$ 1,586,986	$ 4,115,735		$ 41,606,530	$ 3,673,010
9	345	$ 20,356,139	$ 398,530	$ 398,530								
9	Total Accessory Electric Equipment	$ 133,529,862	$ 398,530	$ 398,530	$ 9,360,289	$ 9,996,405	$ 30,152,394	$ 1,586,986	$ 4,115,735	$ -	$ 41,606,530	$ 3,673,010
10	10% Accessory Allocator		10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
10		$ 13,352,986	$ 39,853	$ 39,853	$ 936,029	$ 999,641	$ 3,015,239	$ 158,699	$ 411,573	$ -	$ 4,160,653	$ 367,301
11												
11	GSUs											
12	GSU Owned at Each Tri-State Unit in Western	$ 18,498,054	$ 327,854	$ 327,854	$ 563,249	$ 643,797	$ 3,411,661	$ -	$ -	$ -	$ 3,443,708	$ -
12												
13	Total Investment	$ 2,118,204,291	$ 11,212,347	$ 11,212,347	$ 147,474,794	$ 146,546,722	$ 493,526,235	$ -	$ -	$ -	$ 562,370,313	$ 124,661,193

Tri-State Generating and Transmission Association
Docket No. EL19-_______
Investment Detail of Reactive Components for Western Units

93 Laramie River ST 3 (n)	94 Laramie River Common (o)	70 Limon GT 1 (p)	70 Limon GT 2 (q)	72 Pyramid GT 1 (r)	72 Pyramid GT 2 (s)	72 Pyramid GT 3 (t)	72 Pyramid GT 4 (u)	81 Shafer Thermo Fort Lupton LMA (v)	81 Shafer Thermo Fort Lupton LMB (w)	81 Shafer Thermo Fort Lupton LMC (x)	81 Shafer Thermo Fort Lupton LMD (y)	81 Shafer Thermo Fort Lupton LME (z)	81 Shafer Thermo Fort Lupton ST A (aa)	81 Shafer Thermo Fort Lupton ST B (ab)
$ 29,739,386	$ 4,045,288												$ 20,062,133	$ 20,062,133
		$ 27,856,971	$ 27,856,971	$ 23,502,195	$ 23,502,195	$ 23,502,195	$ 23,502,195	$ 19,679,989	$ 19,679,989	$ 19,679,989	$ 19,679,989	$ 19,679,989		
		$ 8,417	$ 8,417	$ 22,042	$ 22,042	$ 22,042	$ 22,042	$ 4,202,849	$ 4,202,849	$ 4,202,849	$ 4,202,849	$ 4,202,849		
$ 29,739,386	$ 4,045,288	$ 27,865,387	$ 27,865,387	$ 23,524,237	$ 23,524,237	$ 23,524,237	$ 23,524,237	$ 23,882,838	$ 23,882,838	$ 23,882,838	$ 23,882,838	$ 23,882,838	$ 20,062,133	$ 20,062,133
8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
$ 2,596,248	$ 353,154	$ 2,432,648	$ 2,432,648	$ 2,053,666	$ 2,053,666	$ 2,053,666	$ 2,053,666	$ 2,084,972	$ 2,084,972	$ 2,084,972	$ 2,084,972	$ 2,084,972	$ 1,751,424	$ 1,751,424
$ 6,081,785	$ 2,163,490			$ 404,745	$ 404,745	$ 404,745	$ 404,745						$ 1,409,060	$ 1,409,060
		$ 1,875,156	$ 1,875,156					$ 3,161,753	$ 3,161,753	$ 3,161,753	$ 3,161,753	$ 3,161,753		$ -
$ 6,081,785	$ 2,163,490	$ 1,875,156	$ 1,875,156	$ 404,745	$ 404,745	$ 404,745	$ 404,745	$ 3,161,753	$ 3,161,753	$ 3,161,753	$ 3,161,753	$ 3,161,753	$ 1,409,060	$ 1,409,060
10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
$ 608,179	$ 216,349	$ 187,516	$ 187,516	$ 40,474	$ 40,474	$ 40,474	$ 40,474	$ 316,175	$ 316,175	$ 316,175	$ 316,175	$ 316,175	$ 140,906	$ 140,906
$ -	$ -	$ 956,071	$ 956,071	$ 375,643	$ 375,643	$ 375,643	$ 375,643	$ 909,317	$ 909,317	$ 909,317	$ 909,317	$ 909,317	$ 909,317	$ 909,317
$ 157,069,232		$ 38,134,725	$ 38,134,725	$ 27,004,073	$ 27,004,073	$ 27,004,073	$ 27,004,073	$ 39,977,910	$ 39,977,910	$ 39,977,910	$ 39,977,910	$ 39,977,910	$ 39,977,910	$ 39,977,910

Tri-State Generating and Transmission Association
Docket No. EL19-_______
Proposed Capital Structure

Line No. (a)	Item (b)	Percent (c)	Cost (d)	Weighted Cost (e)
1	**Tri-State Proposed Capital Structure**			
2				
3				
4	Long Term Debt	59.71%	4.49%	2.68%
5	Notes Payable	5.05%	2.76%	0.14%
6	Common Stock	35.24%	9.30%	3.28%
7	Total	100.00%		6.10%

Source: Tri-State Proposed Western transmission formula rate

Tri-State Generation and Transmission Association
Docket No. EL19-_______
Allocation of Common Costs to Craig and Laramie River Units

			Common Allocated to Units				Common Allocated to Units	
Line No.	Description	Total Craig	Craig ST 1	Craig ST 2	Craig ST 3	Total Laramie River	Laramie River ST 2	Laramie River ST 3
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Generators - Original Cost							
2	Account 314	102,602,892	20,451,002	24,026,884	58,125,006	57,321,296	25,559,266	31,762,030
3	Account 343	-	-	-	-	-	-	-
4	Account 344	-	-	-	-	-	-	-
5	Total By Unit	102,602,892	20,451,002	24,026,884	58,125,006	57,321,296	25,559,266	31,762,030
6	Tri-State Estimate of Gen/Exciter Cost	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%	8.73%
	Generator and Exciter Cost	$ 8,957,232	$ 1,785,372	$ 2,097,547	$ 5,074,313	$ 5,004,149	$ 2,231,324	$ 2,772,825
6	Accessory Electric Equipment							
7	315	55,211,809	11,947,152	12,583,268	30,681,389	11,918,285	4,754,755	7,163,530
8	345	-	-	-	-	-	-	-
9	Total Accessory Electric Equipment	55,211,809	11,947,152	12,583,268	30,681,389	11,918,285	4,754,755	7,163,530
	10% Accessory Allocator							
10	GSUs							
11	GSU Owned at Each Tri-State Unit in Western	4,618,708	563,249	643,797	3,411,661	-	-	-

Tri-State Generation and Transmission Association, Inc.

Generation Plant Depreciation Study

Generating Plant Facilities

Row No.	Unit (Column A)	State (Column B)	Unit Type (Column C)	Fuel (Column D)	Fuel Sub-Type (Column E)	2011 Report MW (Column F)	SNL Nameplate MW (Column G)	Proposed Band (MW) (Column H)	Sample Size (Column I)	Units Retired (Column J)	Model (Column K)	In Service Year (Column L)	Age (Years) at Beg. 2017 (Column M)	2011 Study Life Span (Years) (Column N)	Actuarial Study Life Span (Years) (Column O)	Recommended Life Span (Years) (Column P)	Estimated Retirement Year (Column Q)
1	**Steam Production**																
2	Craig Unit 1	CO	ST [1]	Coal	Subbituminous				N/A	N/A		1980	N/A	71	N/A	N/A	**2025**
3	Craig Unit 2	CO	ST	Coal	Subbituminous				159	5		1979	38	71	58	60	**2039**
4	Craig Unit 3	CO	ST	Coal	Subbituminous				159	5		1984	33	71	58	60	**2044**
5	Craig Coal Handling	CO														[3]	**2044**
6	Craig Common 1&2	CO														[3]	**2039**
7	Craig Common 1, 2 & 3	CO														[3]	**2044**
8	Escalante	NM	ST	Coal	Subbituminous				84	17		1985	32	71	58	60	**2045**
9	Nucla	CO	ST [2]	Coal	Bituminous												
10	Springerville Unit 3	AZ	ST	Coal	Subbituminous												
11	Laramie River Unit 1	WY	ST	Coal	Subbituminous				159	5		1980	37	N/A	58	60	**2040**
12	Laramie River Unit 2	WY	ST	Coal	Subbituminous				159	5		1981	36	N/A	58	60	**2041**
13	Laramie River Unit 3	WY	ST	Coal	Subbituminous				159	5		1982	35	N/A	58	60	**2042**
14																	
15	**Other Production**																
16	Burlington Unit 1	CO	CT	Oil					494	100	Frame 7b	1977	40	75	51	60	**2037**
17	Burlington Unit 2	CO	CT	Oil					494	100	Frame 7b	1977	40	75	51	60	**2037**
18	Knutson Unit 1	CO	CT	Natural Gas/Oil													
19	Knutson Unit 2	CO	CT	Natural Gas/Oil													
20	Limon Unit 1	CO	CT	Natural Gas/Oil					861	50	Frame 7EA	2002	15	40	46	46	**2048**
21	Limon Unit 2	CO	CT	Natural Gas/Oil					861	50	Frame 7EA	2002	15	40	46	46	**2048**
22	Pyramid Unit 1	NM	CT	Natural Gas/Oil					1197	380	LM-6000	2003	14	47	46	46	**2049**
23	Pyramid Unit 2	NM	CT	Natural Gas/Oil					1197	380	LM-6000	2003	14	47	46	46	**2049**
24	Pyramid Unit 3	NM	CT	Natural Gas/Oil					1197	380	LM-6000	2003	14	47	46	46	**2049**
25	Pyramid Unit 4	NM	CT	Natural Gas/Oil					1197	380	LM-6000	2003	14	47	46	46	**2049**
26																	
27	**Combined Cycle**																
28	Rifle CC	CO	ST	Steam													
29	Rifle CC	CO	CT	Natural Gas													
30	Rifle CC	CO	CT	Natural Gas													
31	Rifle CC	CO	CT	Natural Gas													
32																	
33	**J.M. Shafer**																
34	LMA	CO	CC CT	Natural Gas					626	112	LM-6000	1994	23	N/A	41	41	**2035**
35	LMB	CO	CC CT	Natural Gas					626	112	LM-6000	1994	23	N/A	41	41	**2035**
36	LMC	CO	CC CT	Natural Gas					626	112	LM-6000	1994	23	N/A	41	41	**2035**
37	LMD	CO	CC CT	Natural Gas					626	112	LM-6000	1994	23	N/A	41	41	**2035**
38	LME	CO	CC CT	Natural Gas					626	112	LM-6000	1994	23	N/A	41	41	**2035**
39	STA	CO	CC ST	Steam					140	16		1994	23	N/A	53	53	**2047**
40	STB	CO	CC ST	Steam					140	16		1994	23	N/A	53	53	**2047**
41																	

42 [1] Scheduled retirement date in 2025
43 [2] Scheduled retirement date in 2022, Atmospheric circulating fluidized-bed combustion facility
44 [3] Estimated retirement year for Craig coal handling and common facilities is based on the latest retirement year for the associated Craig generating units.

Tri-State Generation and Transmission Association
Docket No. EL19-_______
Generator and Exciter Investment

Line No. (a)		FACILITY No. Name (b)	FERC REA (c)	Gross Cost At 12/31/2018 (d)	Subtotal (e)	Allocation of GSU or Common (f)	Total (g)
1	FACILITY	FACILITY DESCRIPTION	REA	12/31/18 Cost			
2	22		310				
3	22		311				
4	22		312				
5	22		314				
6	22		315				
7	22		316				
8	22		341				
9	22		342				
10	22		343				
11	22		345				
12	22		346				
13	22 Total	Rifle Generation Station			Not connected to Tri-State Western Transmission		
14	23		310	22,401,290			
15	23		311	108,056,130			
16	23		312	300,281,503			
17	23		314	86,238,014			
18	23		315	41,606,530			
19	23		316	3,786,846			
20	23 Total	Escalante Station		562,370,313	562,370,313		562,370,313
21	26		310				
22	26		311				
23	26		312				
24	26		314				
25	26		315				
26	26		316				
27	26 Total	Nucla Station		-	Nucla has been Mothballed		
28	29		340	182,351			
29	29		341	4,569,556			
30	29		342	660,922			
31	29		343	11,698,404			
32	29		344	2,686,511			
33	29		345	797,061			
34	29		346	1,174,182	Subtotal	GSU	Total
35	29 Total	Burlington Generation Station		21,768,986	21,768,986	655,708	22,424,693
36	31		311	16,702,471			
37	31		312	46,934,280			
38	31		314	15,614,381			
39	31		315	9,360,289			
40	31		316	1,581,108	Subtotal	Common	Total
41	31 Total	Craig Station Unit 1		90,192,529	90,192,529	57,282,265	147,474,794
42	32		311	16,940,477			
43	32		312	42,821,511			
44	32		314	19,190,263			
45	32		315	9,996,405			
46	32		316	315,802	Subtotal	Common	Total
47	32 Total	Craig Station Unit 2		89,264,457	89,264,457	57,282,264.75	146,546,722
48	33		310	10,298,537			
49	33		311	100,480,671			
50	33		312	236,250,670			
51	33		314	54,331,676			
52	33		315	30,152,394			
53	33		316	19,457,711	Subtotal	Common	Total
54	33 Total	Craig Station Unit 3		450,971,660	450,971,660	42,554,574	493,526,235
55	35		310	325,978			
56	35		311	48,455,814			
57	35		312	20,636,921			
58	35		314	11,379,990			
59	35		315	1,586,986			
60	35		316	6,739,560			
61	35 Total	Craig Units 1, 2 & 3 Common		89,125,250	89,125,250		
62	37		310	161,792			
63	37		311	4,513,918			
64	37		312	18,246,227			
65	37		314	2,086,581			
66	37		315	4,115,735			
67	37		316	331,128			
68	37 Total	Craig Units 1 & 2 Common		29,455,381	29,455,381		
69	38		311	1,117,565			
70	38		312	36,904,590			
71	38		315	446,580			
72	38		316	69,738			
73	38 Total	Craig Rail Coal Handling Facilities		38,538,473	38,538,473		
74	47		310				
75	47		311				

Exhibit No. TS-021

Tri-State Generation and Transmission Association
Docket No. EL19-_______
Generator and Exciter Investment

Line No. (a)		FACILITY No. Name (b)	FERC REA (c)	Gross Cost At 12/31/2018 (d)	Subtotal (e)	Allocation of GSU or Common (f)	Total (g)
76	47		312				
77	47		314				
78	47		315				
79	47		316				
80	47 Total	Springerville Generating Station		-	Not connected to Tri-State Western Transmission		
81	70		340	545,967			
82	70		341	13,387,152			
83	70		342	2,276,195			
84	70		343	55,713,942			
85	70		344	16,833			
86	70		345	3,750,312			
87	70		346	579,049			
88	70 Total	Limon Combustion Turbines		76,269,450	76,269,450		76,269,450
89	71		340				
90	71		341				
91	71		342				
92	71		343				
93	71		344				
94	71		345				
95	71		346				
96	71 Total	Frank R. Knutson Generating Station		-	Not connected to Tri-State Western Transmission		
97	72		340	1,617,759			
98	72		341	3,684,848			
99	72		342	4,172,828			
100	72		343	94,008,780			
101	72		344	88,167			
102	72		345	1,618,979			
103	72		346	1,322,357	Subtotal	GSU	Total
104	72 Total	Pyramid Combustion Turbines		106,513,718	106,513,718	1,502,573	108,016,291
105	81		310	44,663,119			
106	81		311	10,736,640			
107	81		312	36,670,719			
108	81		314	40,124,266			
109	81		315	2,818,121			
110	81		316	2,743,328			
111	81		341	3,442,004			
112	81		342	1,765,222			
113	81		343	98,399,943			
114	81		344	21,014,246			
115	81		345	15,808,766			
116	81		346	1,658,993			
117	81 Total	J.M. Shafer Generating Station		279,845,368	279,845,368		279,845,368
118	91		311	9,699,534			
119	91		312	55,125,700			
120	91		314	29,222,428			
121	91		315	2,699,213			
122	91		316	832,732			
123	91 Total	Laramie River Station Unit 1		97,579,607			
124	92		311	8,968,209			
125	92		312	56,266,710			
126	92		314	23,536,622			
127	92		315	3,673,010			
128	92 Total	Laramie River Station Unit 2		92,444,552	92,444,552	32,216,641.27	124,661,193
129	93		311	14,941,319			
130	93		312	74,090,100			
131	93		314	29,739,386			
132	93		315	6,081,785			
133	93 Total	Laramie River Station Unit 3		124,852,590	124,852,590	32,216,641.27	157,069,232
134	94		310	1,323,279			
135	94		311	37,356,056			
136	94		312	49,279,617			
137	94		314	4,045,288			
138	94		315	2,163,490			
139	94		316	2,482,193			
140	94 Total	Laramie River Station Common		96,649,924	96,649,924		
141							
142							
143							
144	Grand Total			2,245,842,259			2,118,204,291

Exhibit No. TS-022

Burlington Unit 1

Nameplate Picture

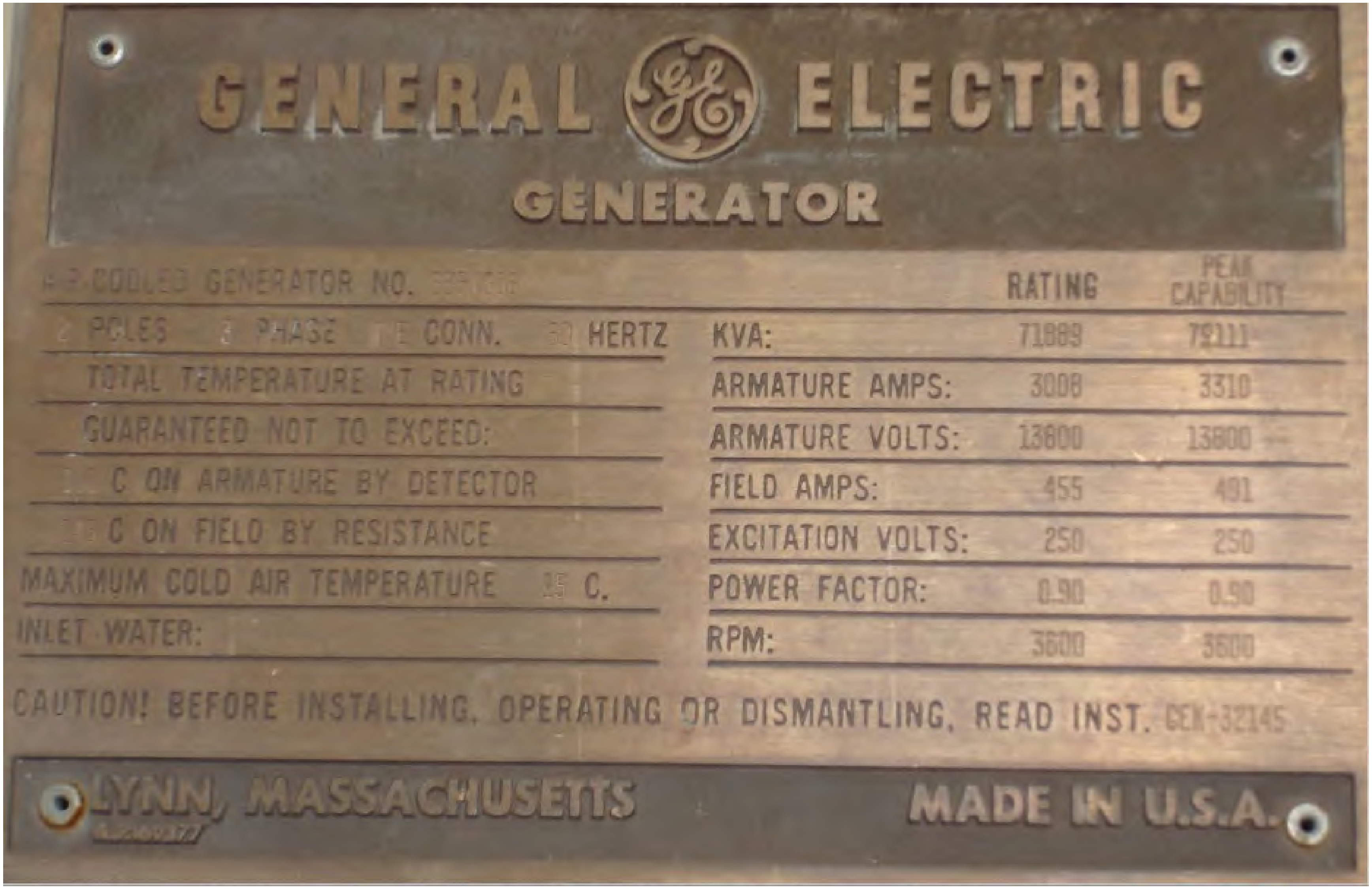

GENERAL ELECTRIC
GENERATOR
GENERATOR NO.
POLES
PHASE
CONN.
HERTZ
TOTAL TEMPERATURE AT RATING
GUARANTEED NOT TO EXCEED:
C ON ARMATURE BY DETECTOR
C ON FIELD BY RESISTANCE
MAXIMUM COLD AIR TEMPERATURE
C.
INLET WATER:
RATING
PEAK CAPABILITY
KVA: 71889
ARMATURE AMPS: 3008 3310
ARMATURE VOLTS: 13800 13800
FIELD AMPS: 455 491
EXCITATION VOLTS: 250 250
POWER FACTOR: 0.90 0.90
RPM: 3600 3600
CAUTION! BEFORE INSTALLING, OPERATING OR DISMANTLING, READ INST. GEK-32145
LYNN, MASSACHUSETTS
MADE IN U.S.A.

Exhibit No. TS-022

Burlington Unit 2

Nameplate Picture

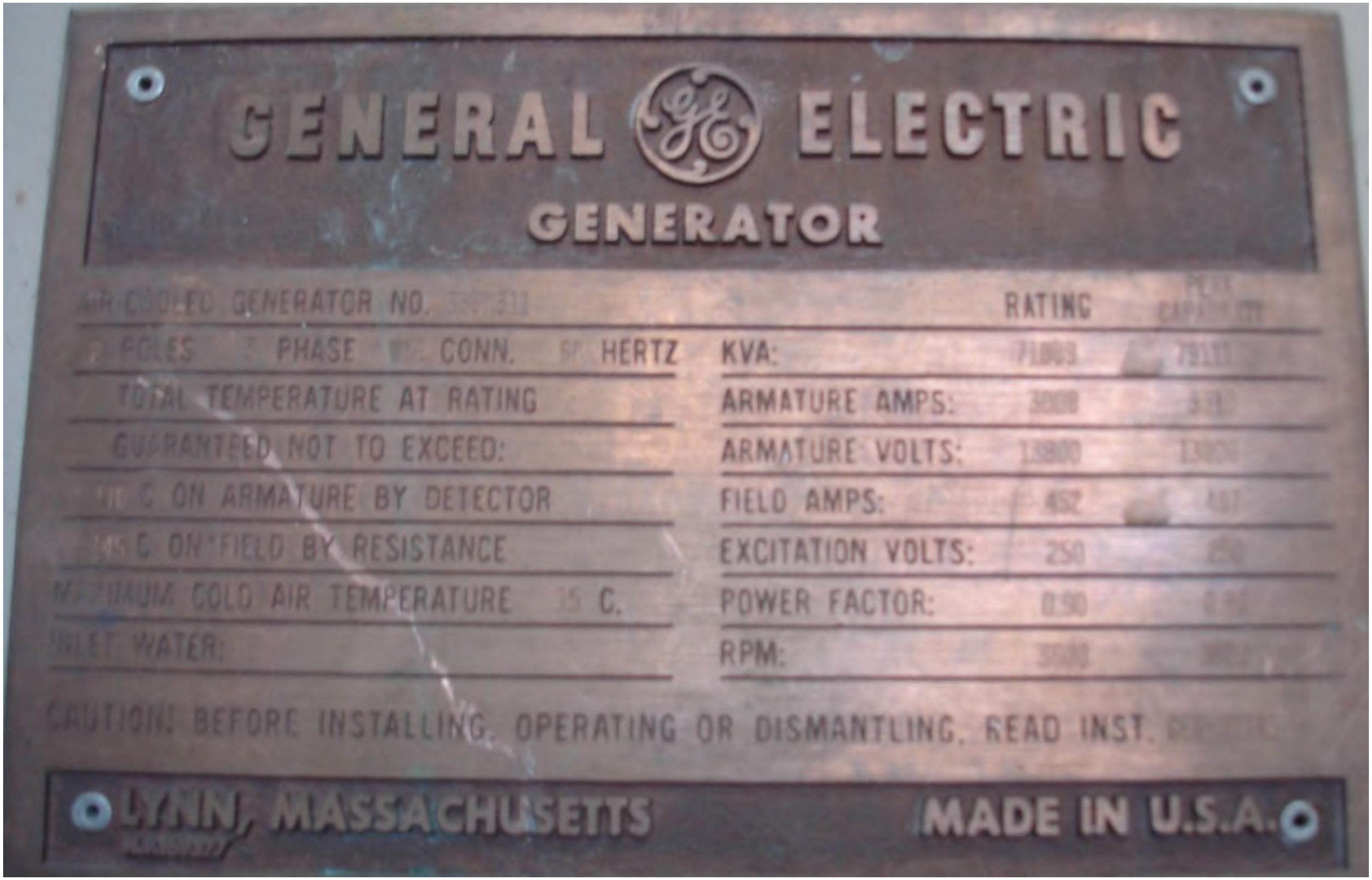

GENERAL ELECTRIC
GENERATOR
AIR COOLED GENERATOR NO.
RATING
POLES PHASE CONN. HERTZ
KVA:
TOTAL TEMPERATURE AT RATING
ARMATURE AMPS:
GUARANTEED NOT TO EXCEED:
ARMATURE VOLTS:
C ON ARMATURE BY DETECTOR
FIELD AMPS:
C ON FIELD BY RESISTANCE
EXCITATION VOLTS: 250
MAXIMUM COLD AIR TEMPERATURE C.
POWER FACTOR:
INLET WATER:
RPM:
CAUTION! BEFORE INSTALLING, OPERATING OR DISMANTLING, READ INST.
LYNN, MASSACHUSETTS
MADE IN U.S.A.

Exhibit No. TS-022

Craig Unit 1

Nameplate Picture


Steam Turbine Generator Unit
TURBINE
TURBINE NO.
RATING: KW
3600 RPM
20 STAGES
STEAM CONDITIONS: PRESSURE 2400 PSIG
TEMPERATURE 1000° F
REHEAT TEMPERATURE 1000° F
EXHAUST PRESSURE: 2" HgA
GENERATOR
HYDROGEN & WATER-COOLED GENERATOR NO. 180X613
RATING
2 POLES 3 PHASE Y CONN. 60 HERTZ
H2 GAS AT: 48 PSIG
TEMPERATURE RISE AT RATED LOAD
KVA: 496000
GUARANTEED NOT TO EXCEED:
ARMATURE AMPS: 13017
51 C ON ARMATURE BY DETECTOR
ARMATURE VOLTS: 22000
C ON FIELD BY RESISTANCE
FIELD AMPS: 3017
EXCITATION VOLTS: 500
POWER FACTOR 0.90
CAUTION! BEFORE INSTALLING, OPERATING OR DISMANTLING, READ INST. GEK-
GE ENERGY
General Electric Company
Schenectady, New York
Made in U.S.A.

Exhibit No. TS-022

Craig Unit 2

Nameplate Picture

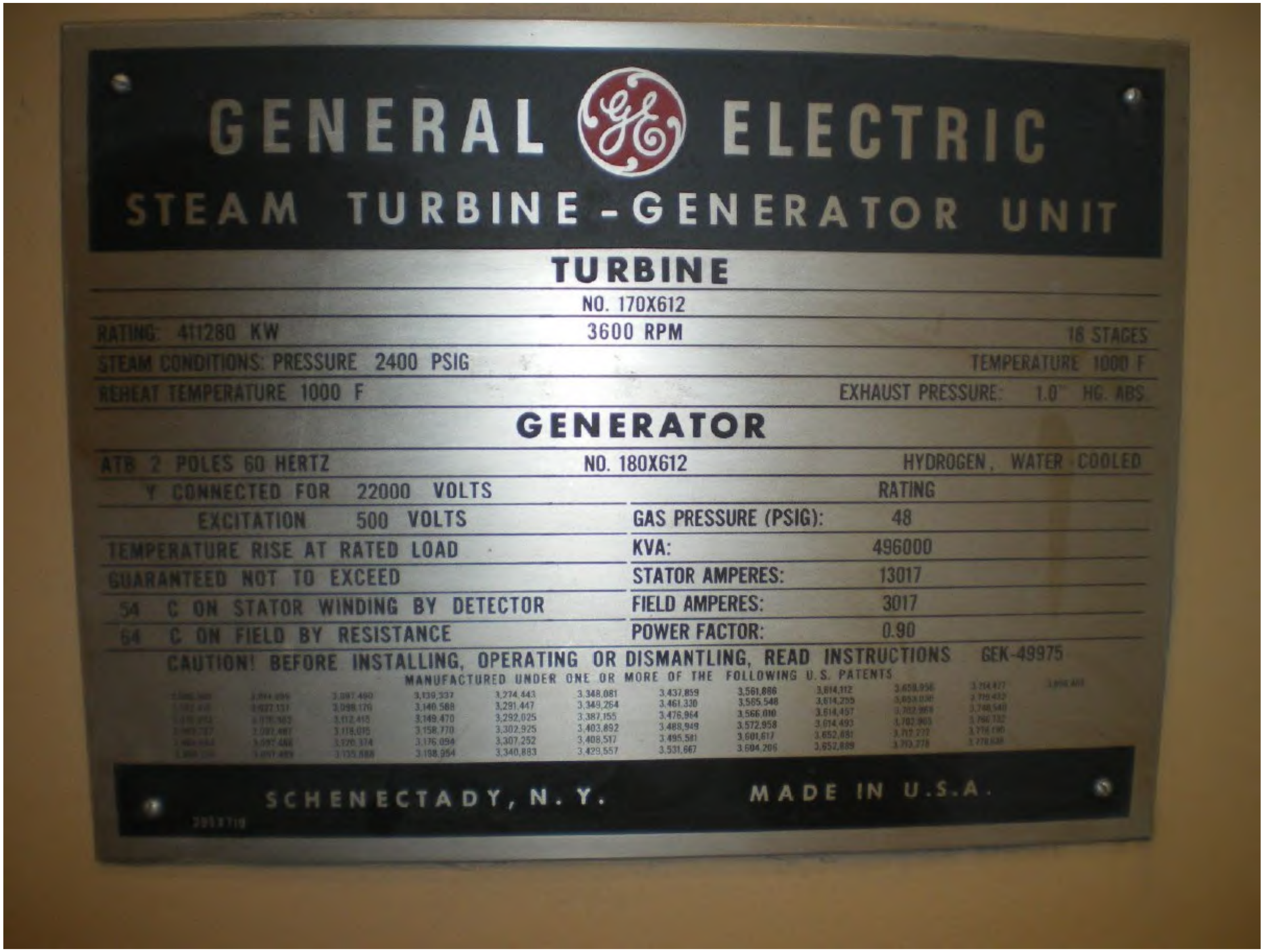

GENERAL ELECTRIC
STEAM TURBINE - GENERATOR UNIT
TURBINE
NO. 170X612
RATING: 411280 KW
3600 RPM
18 STAGES
STEAM CONDITIONS: PRESSURE 2400 PSIG
TEMPERATURE 1000 F
REHEAT TEMPERATURE 1000 F
EXHAUST PRESSURE: 1.0" HG. ABS.
GENERATOR
ATB 2 POLES 60 HERTZ
NO. 180X612
HYDROGEN, WATER COOLED
Y CONNECTED FOR 22000 VOLTS
RATING
EXCITATION 500 VOLTS
GAS PRESSURE (PSIG): 48
TEMPERATURE RISE AT RATED LOAD
KVA: 496000
GUARANTEED NOT TO EXCEED
STATOR AMPERES: 13017
54 C ON STATOR WINDING BY DETECTOR
FIELD AMPERES: 3017
64 C ON FIELD BY RESISTANCE
POWER FACTOR: 0.90
CAUTION! BEFORE INSTALLING, OPERATING OR DISMANTLING, READ INSTRUCTIONS GEK-49975
MANUFACTURED UNDER ONE OR MORE OF THE FOLLOWING U.S. PATENTS
SCHENECTADY, N. Y.
MADE IN U.S.A.

Exhibit No. TS-022

Craig Unit 3

Nameplate Picture

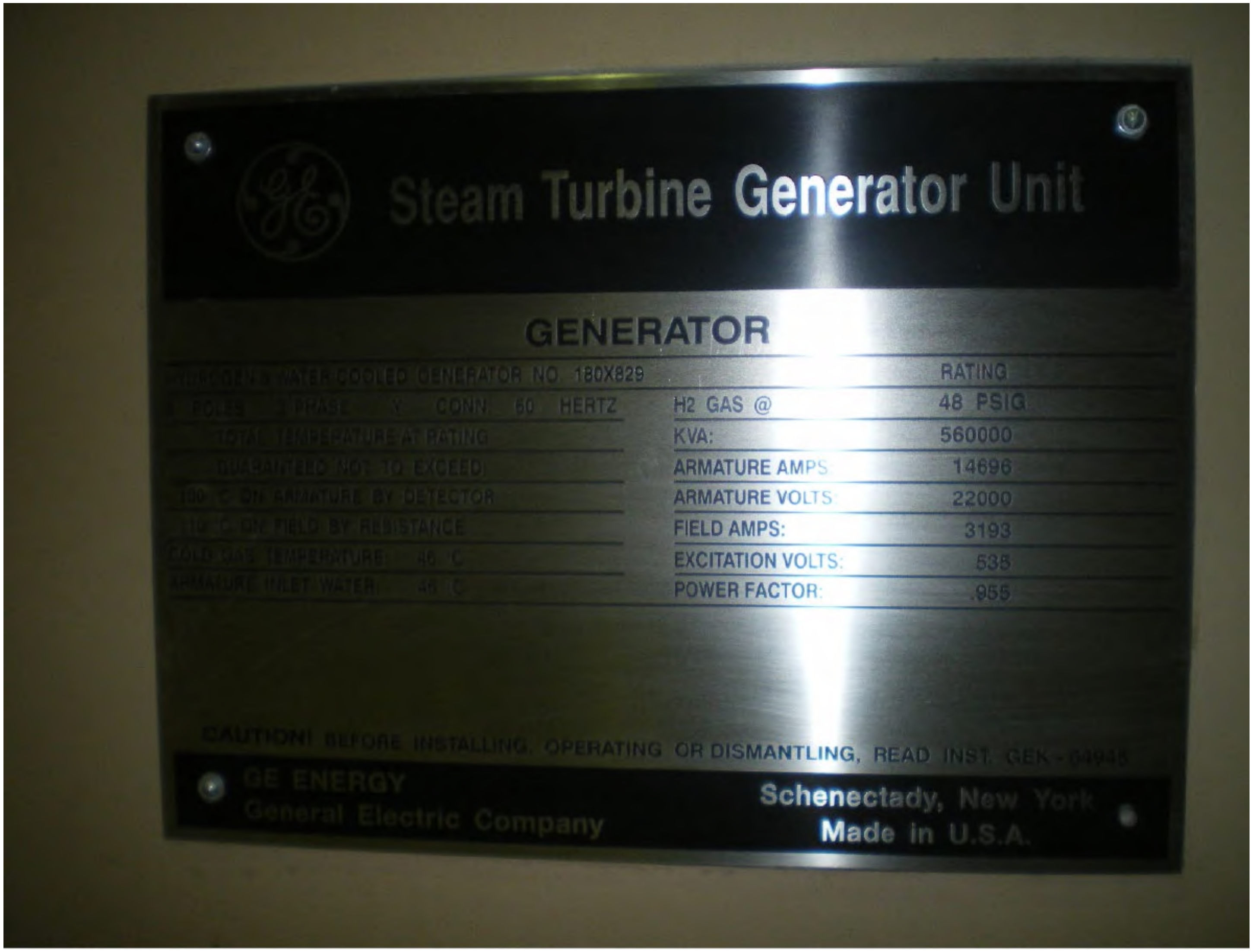

Steam Turbine Generator Unit
GENERATOR
WATER COOLED GENERATOR NO. 180X829
Y CONN. 60 HERTZ
TOTAL TEMPERATURE AT RATING
GUARANTEED NOT TO EXCEED
ON ARMATURE BY DETECTOR
ON FIELD BY RESISTANCE
COLD GAS TEMPERATURE
ARMATURE INLET WATER
RATING
H2 GAS @ 48 PSIG
KVA: 560000
ARMATURE AMPS 14696
ARMATURE VOLTS 22000
FIELD AMPS: 3193
EXCITATION VOLTS: 535
POWER FACTOR: .955
CAUTION! BEFORE INSTALLING, OPERATING OR DISMANTLING, READ INST.
GE ENERGY
General Electric Company
Schenectady, New York
Made in U.S.A.

Exhibit No. TS-022

Escalante

Nameplate Picture

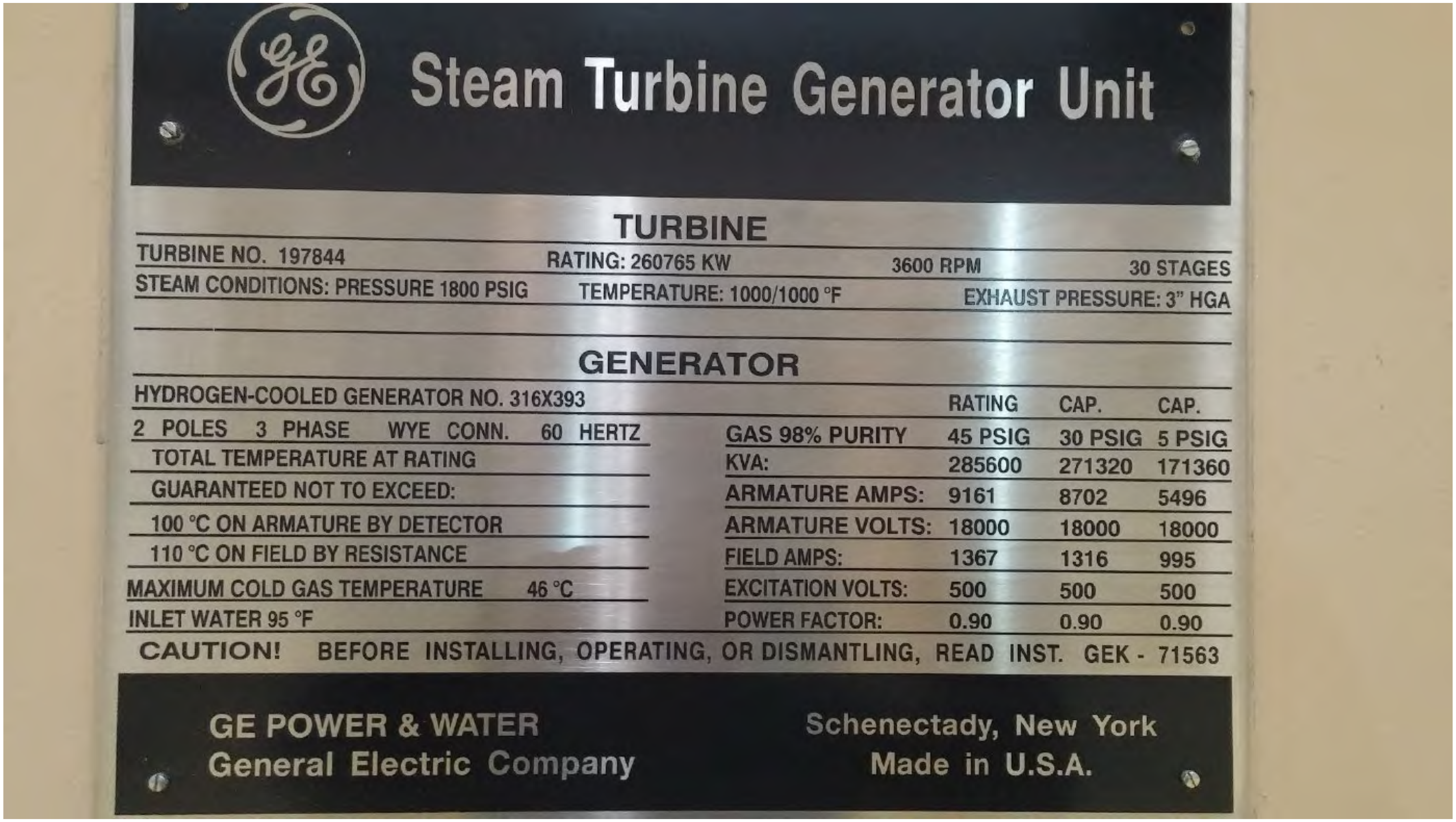

GE
Steam Turbine Generator Unit
TURBINE
TURBINE NO. 197844
RATING: 260765 KW
3600 RPM
30 STAGES
STEAM CONDITIONS: PRESSURE 1800 PSIG
TEMPERATURE: 1000/1000 °F
EXHAUST PRESSURE: 3" HGA
GENERATOR
HYDROGEN-COOLED GENERATOR NO. 316X393
RATING
CAP.
CAP.
2 POLES 3 PHASE WYE CONN. 60 HERTZ
TOTAL TEMPERATURE AT RATING
GUARANTEED NOT TO EXCEED:
100 °C ON ARMATURE BY DETECTOR
110 °C ON FIELD BY RESISTANCE
MAXIMUM COLD GAS TEMPERATURE 46 °C
INLET WATER 95 °F
GAS 98% PURITY 45 PSIG 30 PSIG 5 PSIG
KVA: 285600 271320 171360
ARMATURE AMPS: 9161 8702 5496
ARMATURE VOLTS: 18000 18000 18000
FIELD AMPS: 1367 1316 995
EXCITATION VOLTS: 500 500 500
POWER FACTOR: 0.90 0.90 0.90
CAUTION! BEFORE INSTALLING, OPERATING, OR DISMANTLING, READ INST. GEK - 71563
GE POWER & WATER
General Electric Company
Schenectady, New York
Made in U.S.A.

Exhibit No. TS-022

Laramie River Unit 2

Nameplate Picture

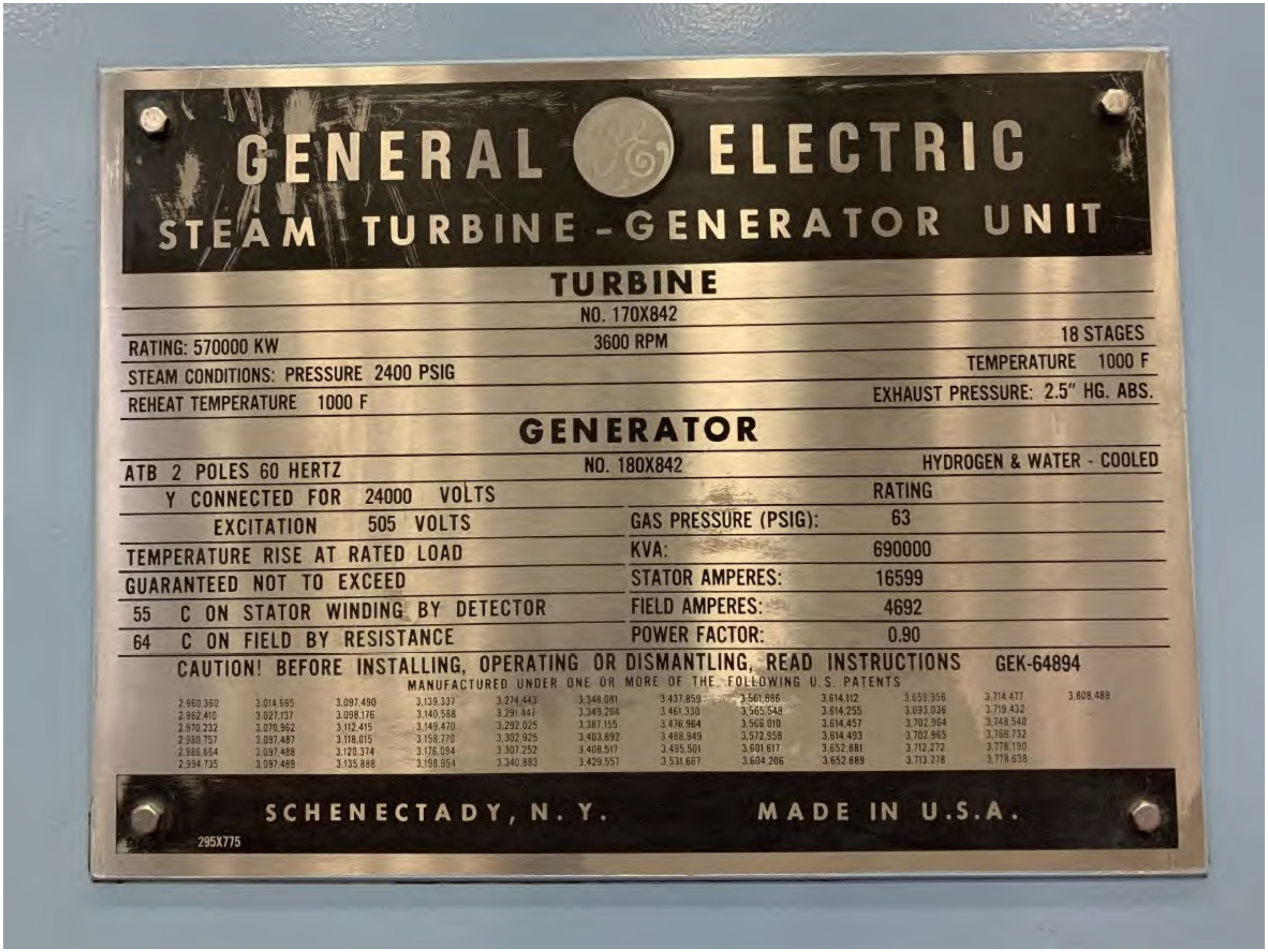

GENERAL ELECTRIC
STEAM TURBINE-GENERATOR UNIT
TURBINE
NO. 170X842
RATING: 570000 KW
3600 RPM
18 STAGES
STEAM CONDITIONS: PRESSURE 2400 PSIG
TEMPERATURE 1000 F
REHEAT TEMPERATURE 1000 F
EXHAUST PRESSURE: 2.5" HG. ABS.
GENERATOR
ATB 2 POLES 60 HERTZ
NO. 180X842
HYDROGEN & WATER - COOLED
Y CONNECTED FOR 24000 VOLTS
RATING
EXCITATION 505 VOLTS
GAS PRESSURE (PSIG): 63
TEMPERATURE RISE AT RATED LOAD
KVA: 690000
GUARANTEED NOT TO EXCEED
STATOR AMPERES: 16599
55 C ON STATOR WINDING BY DETECTOR
FIELD AMPERES: 4692
64 C ON FIELD BY RESISTANCE
POWER FACTOR: 0.90
CAUTION! BEFORE INSTALLING, OPERATING OR DISMANTLING, READ INSTRUCTIONS GEK-64894
MANUFACTURED UNDER ONE OR MORE OF THE FOLLOWING U.S. PATENTS
2,960,360 2,962,410 2,970,232 2,980,757 2,986,664 2,994,735
3,014,695 3,027,137 3,070,962 3,097,487 3,097,488 3,097,489
3,097,490 3,098,176 3,112,415 3,118,015 3,120,374 3,135,888
3,139,337 3,140,588 3,149,470 3,158,770 3,176,094 3,198,954
3,274,443 3,291,447 3,292,025 3,302,925 3,307,252 3,340,883
3,348,081 3,349,264 3,387,155 3,403,692 3,408,517 3,429,557
3,437,859 3,461,330 3,476,964 3,488,949 3,495,501 3,531,667
3,561,886 3,565,548 3,566,010 3,572,958 3,601,617 3,604,206
3,614,112 3,614,255 3,614,457 3,614,493 3,652,881 3,652,889
3,659,956 3,693,036 3,702,964 3,702,965 3,712,272 3,713,278
3,714,477 3,719,432 3,748,540 3,766,732 3,778,190 3,778,638
3,808,489
SCHENECTADY, N. Y.
MADE IN U.S.A.
295X775

Exhibit No. TS-022

Laramie River Unit 3

Nameplate Picture

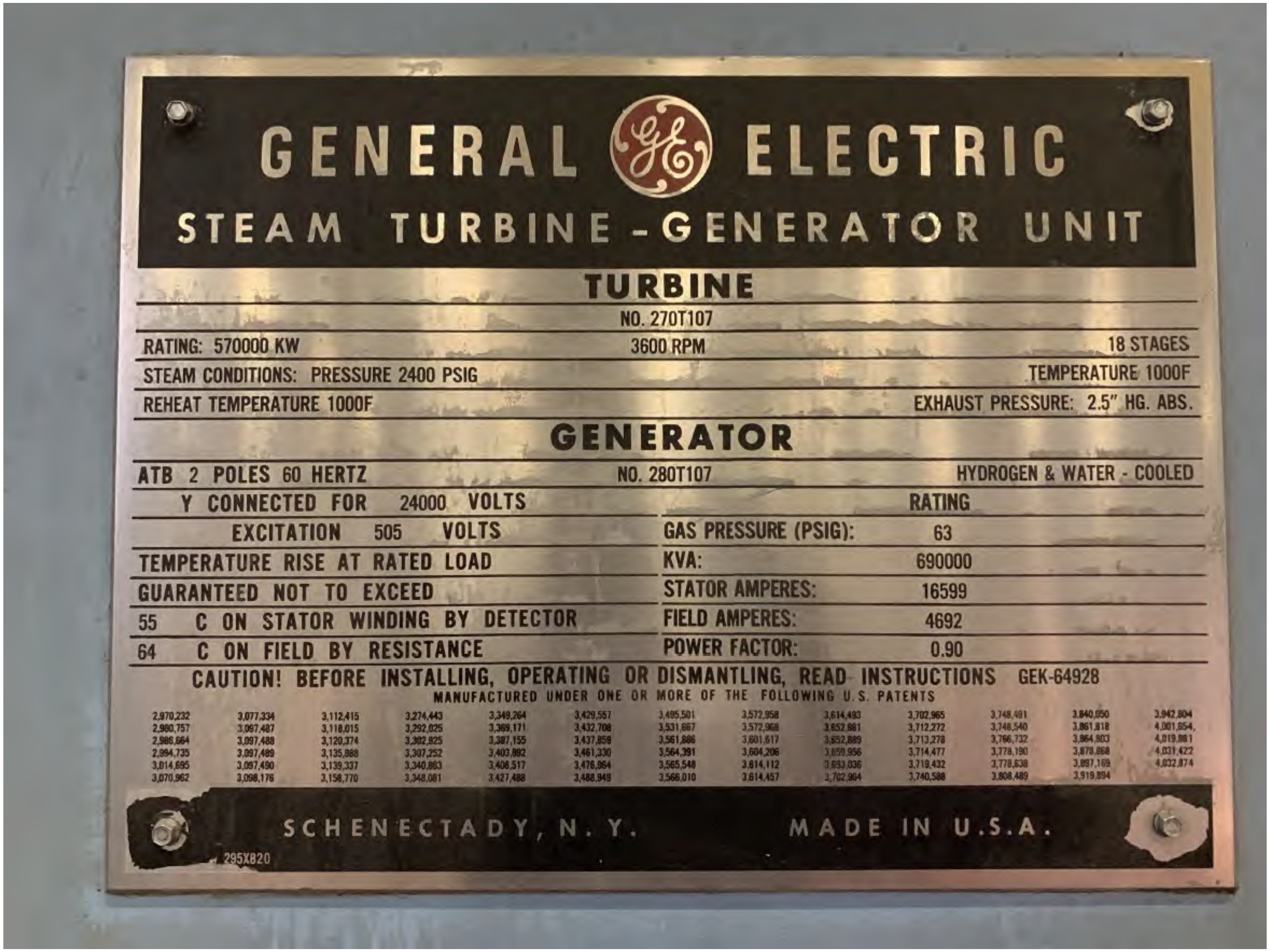

GENERAL ELECTRIC
STEAM TURBINE - GENERATOR UNIT
TURBINE
NO. 270T107
RATING: 570000 KW
3600 RPM
18 STAGES
STEAM CONDITIONS: PRESSURE 2400 PSIG
TEMPERATURE 1000F
REHEAT TEMPERATURE 1000F
EXHAUST PRESSURE: 2.5" HG. ABS.
GENERATOR
ATB 2 POLES 60 HERTZ
NO. 280T107
HYDROGEN & WATER - COOLED
Y CONNECTED FOR 24000 VOLTS
RATING
EXCITATION 505 VOLTS
GAS PRESSURE (PSIG): 63
TEMPERATURE RISE AT RATED LOAD
KVA: 690000
GUARANTEED NOT TO EXCEED
STATOR AMPERES: 16599
55 C ON STATOR WINDING BY DETECTOR
FIELD AMPERES: 4692
64 C ON FIELD BY RESISTANCE
POWER FACTOR: 0.90
CAUTION! BEFORE INSTALLING, OPERATING OR DISMANTLING, READ INSTRUCTIONS GEK-64928
MANUFACTURED UNDER ONE OR MORE OF THE FOLLOWING U.S. PATENTS
2,970,232 3,077,334 3,112,415 3,274,443 3,349,264 3,429,557 3,495,501 3,572,958 3,614,493 3,702,965 3,748,491 3,840,050 3,942,804
2,980,757 3,097,487 3,118,015 3,292,025 3,369,171 3,432,708 3,531,667 3,572,968 3,652,881 3,712,272 3,748,540 3,861,818 4,001,654,
2,986,664 3,097,488 3,120,374 3,302,925 3,387,155 3,437,859 3,561,886 3,601,617 3,652,889 3,713,278 3,766,732 3,864,803 4,019,881
2,994,735 3,097,489 3,135,888 3,307,252 3,403,892 3,461,330 3,564,391 3,604,206 3,659,956 3,714,477 3,778,190 3,878,868 4,031,422
3,014,695 3,097,490 3,139,337 3,340,883 3,406,517 3,476,964 3,565,548 3,614,112 3,693,036 3,719,432 3,778,638 3,897,169 4,032,874
3,070,962 3,098,176 3,158,770 3,348,081 3,427,488 3,488,949 3,566,010 3,614,457 3,702,964 3,740,588 3,808,489 3,919,894
SCHENECTADY, N. Y.
MADE IN U.S.A.
295X820

Exhibit No. TS-022

Limon Units 1-2

Nameplate Picture


SH ELECTRICAL MACHINES LT
BRUSH
BRUSH ELECTRICAL MACHINES
SYNCHRONOUS MACHINE
OUTPUT 90800 KVA
R/MIN. 3600
VOLTS 13800
AMPS 3799
P.F. 0.85
PHASES/HZ. 3/60
PHASE CONN. STAR
EXC. VOLTS 119
EXC. AMPS 1285
DATE 2001
WT. OF M/C.
GE SERIAL 338X966
GE BOOK GEK 107333
TURBOGENERATOR TYPE
BDAX 8-365ER FRAME
902949.010 MACHINE NO.
CONTINUOUS RATING
ANSI C50.14 SPEC.
15°C AMB. TEMP
1660m ALTITUDE
Air at 15°C COOLANT
Class F ROTOR INSULN.
Class F STATOR INSULN.
PROTECTION
BRUSH ELECTRICAL MACHINES LIMITED
LOUGHBOROUGH, ENGLAND
www.fki-eng.com/bem

Exhibit No. TS-022

Pyramid Units 1-4

Nameplate Picture


BRUSH
BRUSH BEM Ltd.
FKI Energy Technology
SYNCHRONOUS MACHINE
OUTPUT 71176 KVA
REV/MIN 3600
VOLTS 13800
AMPS 2977
P.F. 0,85
PHASES / HZ 3/60
PHASE CONN STAR
EXC. VOLTS 185
EXC. AMPS 952
DATE 2002
W.T. OF M/C
WITHOUT AIR
TREATMENT 73360 kg
TURBOGENERATOR TYPE
BDAX 7-290ERJT FRAME
905061.010 MACHINE NO.
CONTINUOUS RATING
ANSI C50.14 SPEC.
15 °C AMB. TEMP
Up to 1000 m ALTITUDE
Air at 15 °C COOLANT
CLASS F ROTOR INSULN.
CLASS F STATOR INSULN.
IP20 PROTECTION
BRUSH ELECTRICAL MACHINES LIMITED
LOUGHBOROUGH, ENGLAND
www.fki-et.com
PHASE SEQUENCE
ROTATION ANTI-CLOCKWISE
LOOKING ON CONNECTION END
WITH ANSI C50.10 1977

Exhibit No. TS-022

Schafer Units 1-7

Nameplate Picture


HAWKER
SIDDELEY
BRUSH
BRUSH ELECTRICAL MACHINES
SYNCHRONOUS MACHINE.
OUTPUT 57412 KVA
R/MIN 3600
VOLTS 13800
AMPS 2402
P.F. 0.850
PHASES/HZ 3/60
PHASE CONN. STAR
EXC.VOLTS 245
EXC.AMPS 439
DATE 1993
WT. OF M/C.
TURBO-GENERATOR TYPE
BDAX 7-290ESS FRAME
61723A-6G MACHINE NO.
CONTINUOUS RATING
ANSI C50.14 SPEC.
15.0°C AMB.TEMP.
UP TO 1000 m ALTITUDE
AIR COOLANT
CLASS F ROTOR INSULN.
CLASS F STATOR INSULN.
BRUSH ELECTRICAL MACHINES LIMITED.
LOUGHBOROUGH. ENGLAND.
PHASE SEQUENCE
T1-T3-T2
ROTATION ANTI-CLOCKWISE
LOOKING ON CONNECTION END

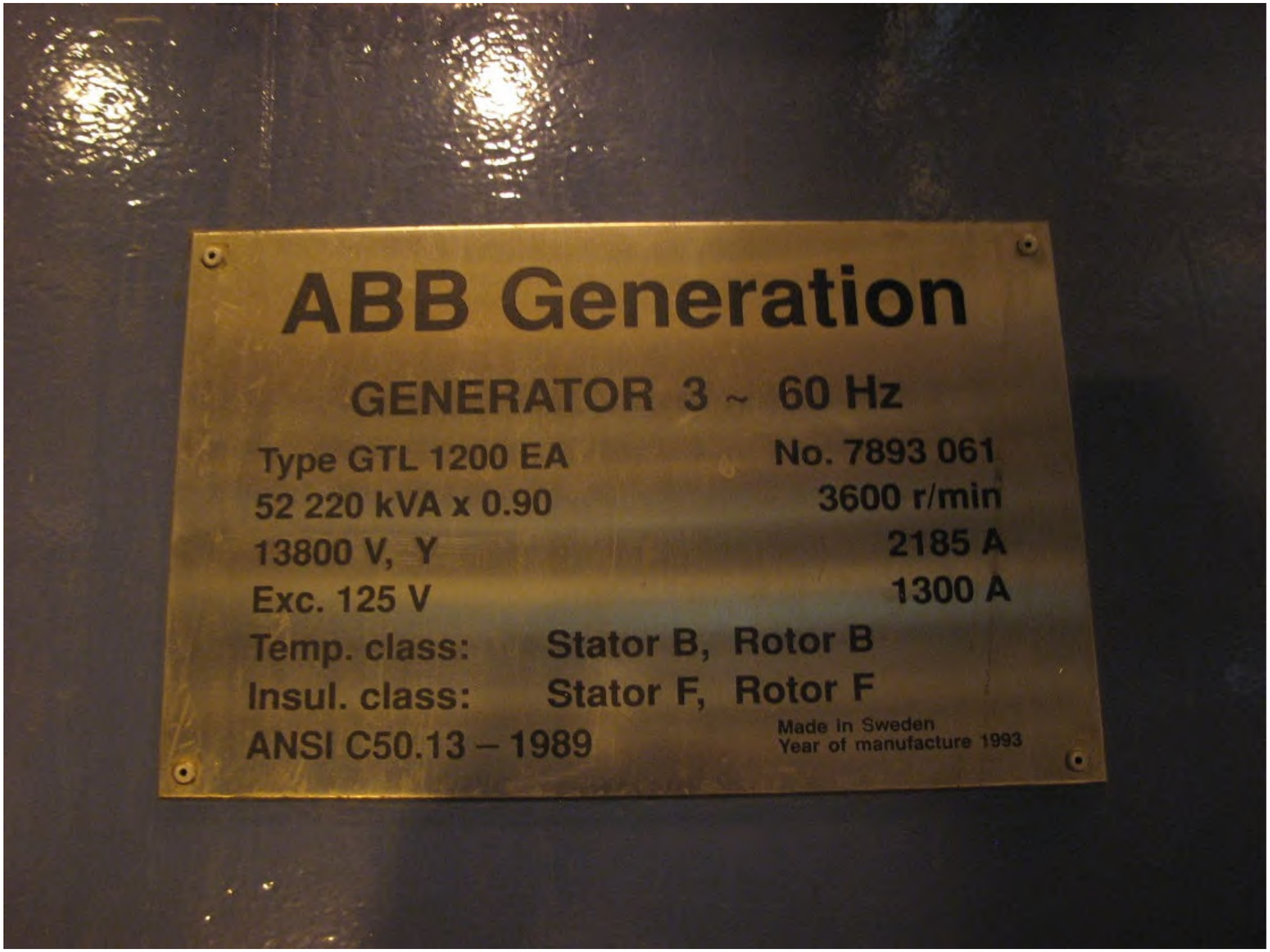


ABB Generation
GENERATOR 3 ~ 60 Hz
Type GTL 1200 EA
No. 7893 061
52 220 kVA x 0.90
3600 r/min
13800 V, Y
2185 A
Exc. 125 V
1300 A
Temp. class: Stator B, Rotor B
Insul. class: Stator F, Rotor F
ANSI C50.13 – 1989
Made in Sweden
Year of manufacture 1993

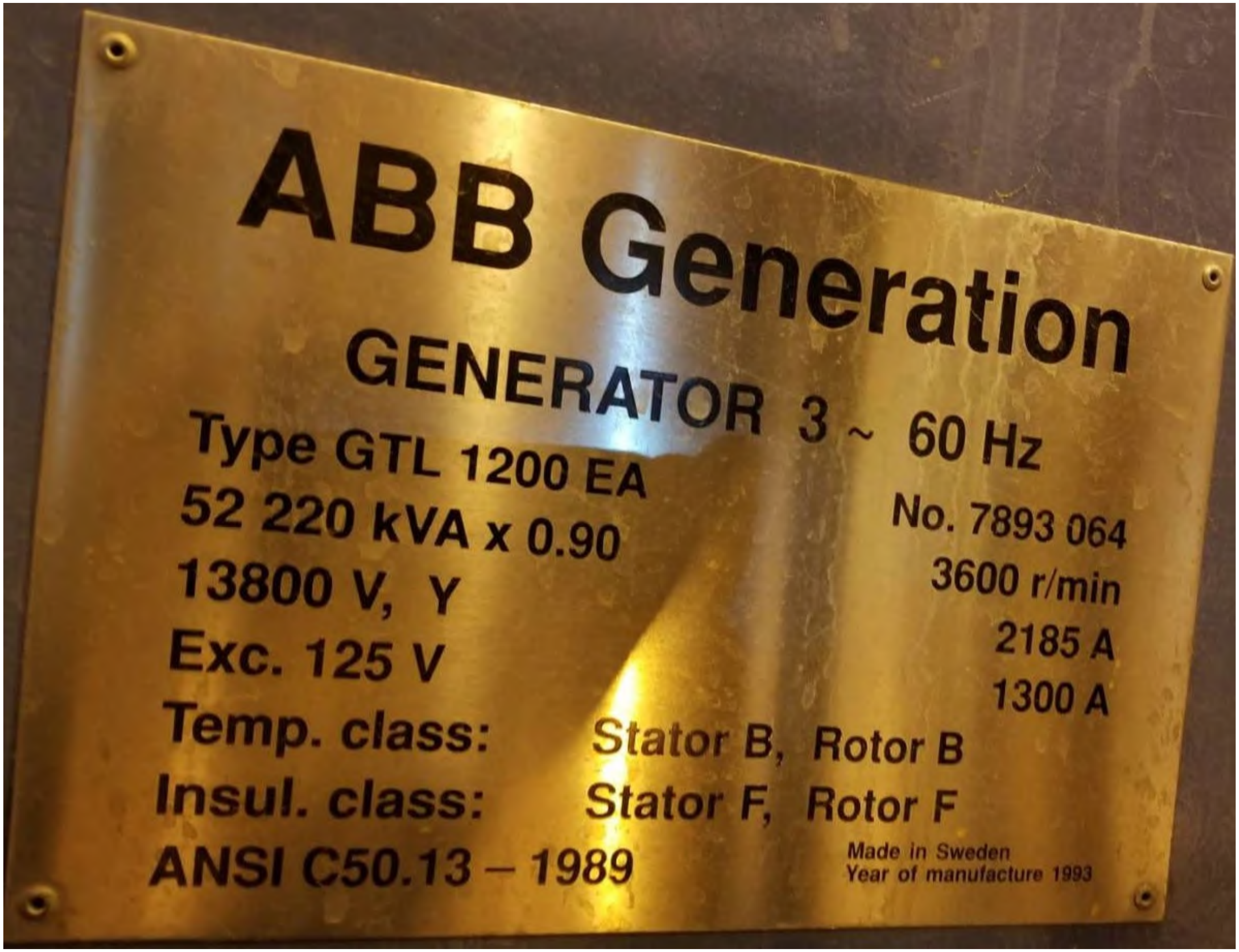


ABB Generation
GENERATOR 3 ~ 60 Hz
Type GTL 1200 EA
No. 7893 064
52 220 kVA x 0.90
3600 r/min
13800 V, Y
2185 A
Exc. 125 V
1300 A
Temp. class: Stator B, Rotor B
Insul. class: Stator F, Rotor F
ANSI C50.13 – 1989
Made in Sweden
Year of manufacture 1993

Exhibit No. TS-023

Burlington Unit 1-2

MOD-025 Test Reports and Capability Curves

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

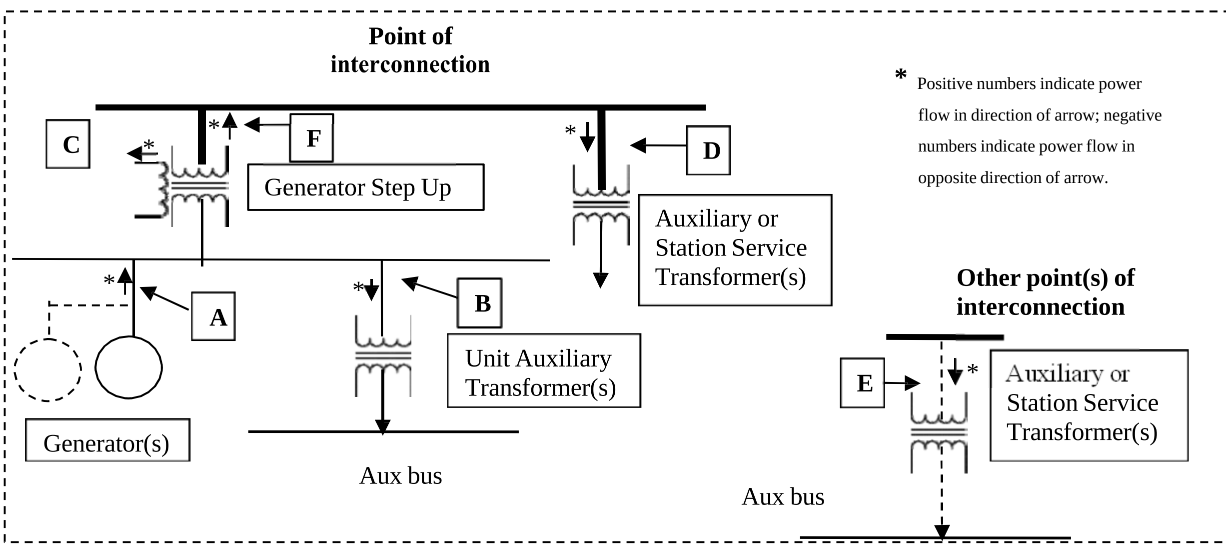
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: Burlington Generating Station **Unit: #1** **Date of Report: 05/02/2018**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A1	13.32 kV	25.3 MW	-13.85 Mvar	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	13.32 kV	0.12612 MW	0.097 Mvar	Station Service Transformer
B3	13.32 kV	0.0123 MW	0.001 Mvar	Cranking Motor Transformer
B	13.32 kV	0.13842 MW	0.09806 Mvar	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
D		MW	Mvar	Sum Start-up transformers
Identify calculated values, if any: D=D1 + D2				
F1	118.74 kV	24.7 MW	-15.2 Mvar	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A1	14.16 kV	24.5 MW	18.43 Mvar	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	14.16 kV	0.1263 MW	0.1165 Mvar	Station Service Transformer
B3	14.16 kV	0.01233 MW	0.001 Mvar	Cranking Motor Transformer
B	14.16 kV	0.13863 MW	0.1175 Mvar	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
D	kV	MW	Mvar	Sum Start-up transformers
Identify calculated values, if any: D=D1 + D2				
F1	120.46 kV	24.4 MW	17.2 Mvar	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A1	**13.37 kV**	**51.5 MW**	**-8.77 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**13.37 kV**	**0.12527 MW**	**0.10073 Mvar**	Station Service Transformer
B3	**13.37 kV**	**0.0123 MW**	**0.001 Mvar**	Cranking Motor Transformer
B	**13.37 kV**	**0.13757 MW**	**0.10173 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
D	**0 kV**	**MW**	**Mvar**	Sum Start-up transformers
Identify calculated values, if any: D=D1 + D2				
F1	**119.22 kV**	**51.3 MW**	**-13.5 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A1	**14.18 kV**	**51.5 MW**	**19.21 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**14.18 kV**	**0.1260 MW**	**0.1175 Mvar**	Station Service Transformer
B3	**14.18 kV**	**0.0123 MW**	**0.001 Mvar**	Cranking Motor Transformer
B	**14.18 kV**	**0.1383 MW**	**0.1185 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
D	**kV**	**MW**	**Mvar**	Sum Start-up transformers
Identify calculated values, if any: D=D1 + D2				
F1	**121.07 kV**	**51.3 MW**	**14.18 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-13.85	
GSU Reactive Power (Mvar)	-1.235	
Net Leading Reactive Power Capability (Mvar)	-15.2	
Gross Lagging Reactive Power Capability (Mvar)	19.21	
GSU Lagging Reactive Power (Mvar)	4.03	
Net Lagging Reactive Power Capability (Mvar)	14.18	
Gross Real Power Capability Minimum Stable Load (MW)	25.3	
Gross Real Power Capability Maximum output (MW)	51.5	
Station Service Reactive Load (Mvar)	0.10895	
Station Service Real Load (MW)	0.13823	
Net Unit Maximum Real Power Output (MW)	51.3	
GSU Real Power Losses (MW)	0.062	
GSU Reactive Losses (Mvar)	-4.88	

Summary of Verification

- Date of Verification: 04/22/2018
- Verification Start Time: 1505 MDT
- Verification End Time: 1655 MDT
- Scheduled Voltage: 120 kV
- Transformer Voltage Ratio:
  - GSU: 8.90
  - Station Service Transformer: 28.125

- Transformer Tap Setting:
    - GSU: _1_
    - Station Service Transformer: _4_

- Ambient conditions at the end of the verification period:
    - Air temperature:: _55 oF_
    - Humidity: _48 %_
    - Stator Temperature: _165 ^{o}F_

Date that data shown in last verification column in table above was taken: _04/22/2018_

Remarks :

Large amount of wind energy in the area holding the Voltage relatively stable on 115 kV system.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

- Generator hydrogen pressure at time of test (if applicable) ______________

Date that data shown in last verification column in table above was taken ______________

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

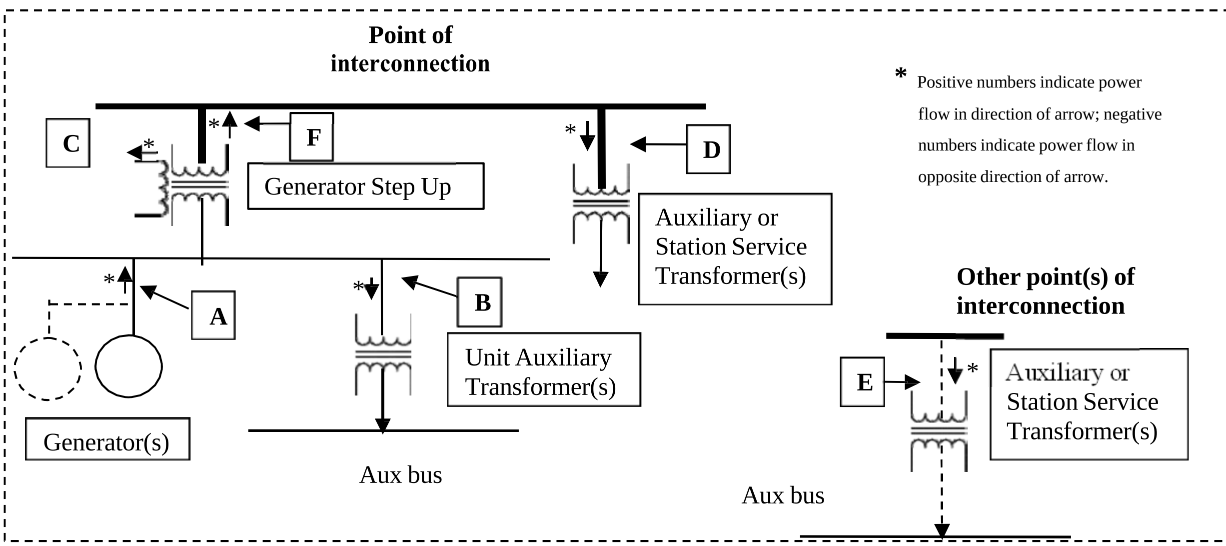
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: Burlington Generating Station **Unit: #2** **Date of Report: 05/02/2018**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A2	**13.17 kV**	**24.9 MW**	**-17.29 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**13.17 kV**	**0.12195 MW**	**0.1091 Mvar**	Station Service Transformer
B4	**13.17 kV**	**0.0123 MW**	**0.001 Mvar**	Cranking Motor Transformer
B	**13.17 kV**	**0.13425 MW**	**0.1101 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
D		**MW**	**Mvar**	Sum Start-up transformers
Identify calculated values, if any: D=D1 + D2				
F2	**119.25 kV**	**24.8 MW**	**-19.5 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A2	**14.36 kV**	**25.7 MW**	**25.7 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**14.36 kV**	**0.123897 MW**	**0.1404 Mvar**	Station Service Transformer
B4	**14.36 kV**	**0.01233 MW**	**0.001 Mvar**	Cranking Motor Transformer
B	**14.36 kV**	**庁.1513 MW**	**0.1414 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
D	**kV**	**MW**	**Mvar**	Sum Start-up transformers
Identify calculated values, if any: D=D1 + D2				
F2	**121.7 kV**	**25.3 MW**	**23.4 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A2	**13.2 kV**	**50.6 MW**	**-11.2 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**13.2 kV**	**0.1459 MW**	**0.1084 Mvar**	Station Service Transformer
B4	**13.2 kV**	**0.0123 MW**	**0.001 Mvar**	Cranking Motor Transformer
B	**13.2 kV**	**0.1582 MW**	**0.1094 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
D	**0 kV**	**MW**	**Mvar**	Sum Start-up transformers
Identify calculated values, if any: D=D1 + D2				
F2	**119.0 kV**	**50.2 MW**	**-16.1Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A2	**14.16 kV**	**51.1 MW**	**19.7 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**14.16 kV**	**0.1509 MW**	**0.1175 Mvar**	Station Service Transformer
B4	**14.16 kV**	**0.0123 MW**	**0.001 Mvar**	Cranking Motor Transformer
B	**14.16 kV**	**0.1632 MW**	**0.1185 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
D	**kV**	**MW**	**Mvar**	Sum Start-up transformers
Identify calculated values, if any: D=D1 + D2				
F2	**121.0 kV**	**50.5 MW**	**14.6 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-17.29	
GSU Reactive Power (Mvar)	-2.21	
Net Leading Reactive Power Capability (Mvar)	-19.5	
Gross Lagging Reactive Power Capability (Mvar)	25.7	
GSU Lagging Reactive Power (Mvar)	2.3	
Net Lagging Reactive Power Capability (Mvar)	23.4	
Gross Real Power Capability Minimum Stable Load (MW)	25.7	
Gross Real Power Capability Maximum output (MW)	51.1	
Station Service Reactive Load (Mvar)	0.1336	
Station Service Real Load (MW)	0.1632	
Net Unit Maximum Real Power Output (MW)	50.2	
GSU Real Power Losses (MW)	0.437	
GSU Reactive Losses (Mvar)	-4.9	

Summary of Verification

- Date of Verification: 04/26/2018
- Verification Start Time: 1900 MDT
- Verification End Time: 2105MDT
- Scheduled Voltage: 120 kV
- Transformer Voltage Ratio:
  - GSU: 8.90
  - Station Service Transformer: 28.125

- Transformer Tap Setting:
  - GSU: 1
  - Station Service Transformer: 4

- Ambient conditions at the end of the verification period:
  - Air temperature: 55 ^{o}F
  - Humidity: 35.3 %
  - Stator Temperature: 158 ^{o}F

Date that data shown in last verification column in table above was taken: 04/26/2018

Remarks :

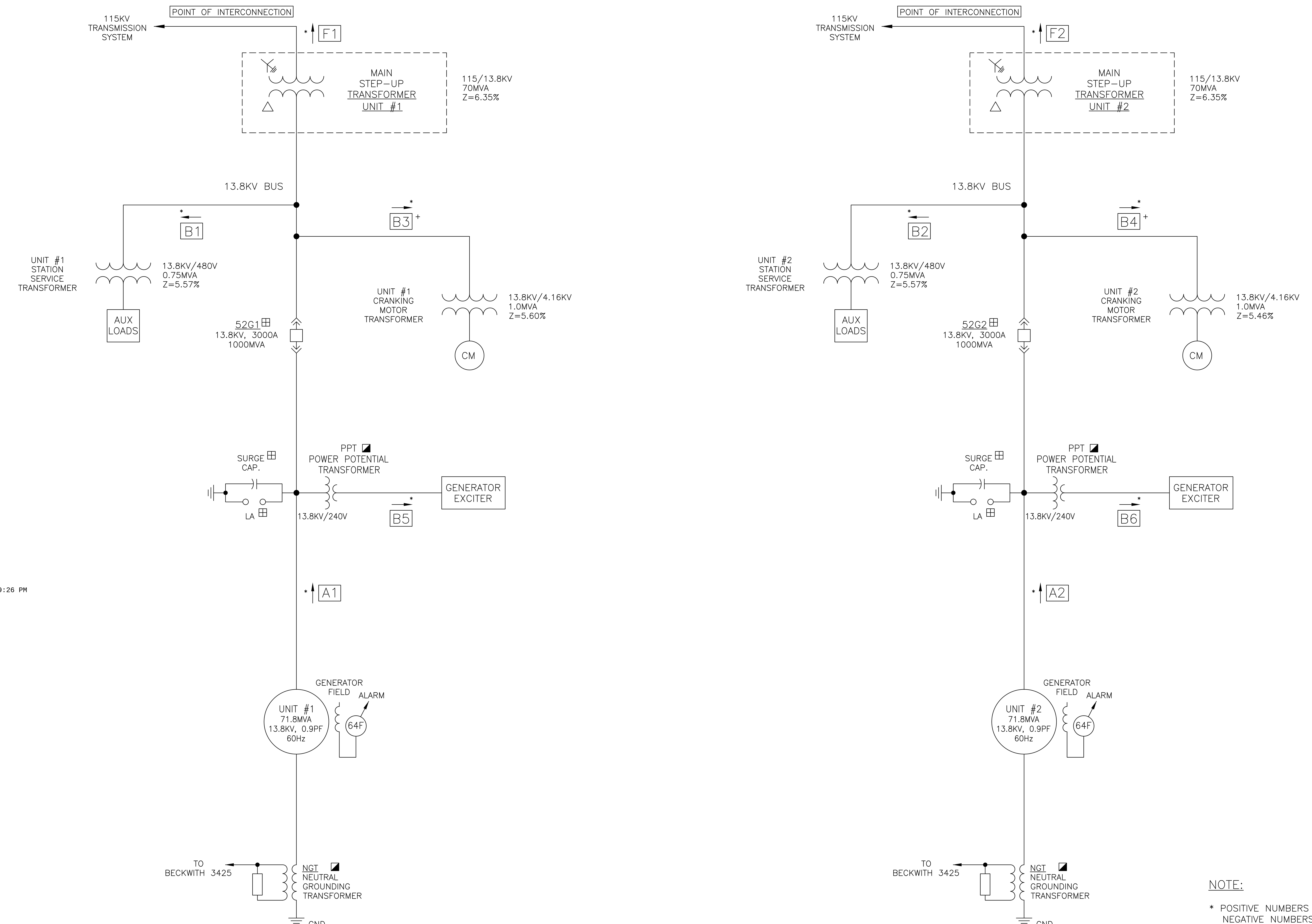
Large amount of wind energy in the area holding the Voltage relatively stable on 115 kV system.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

- Generator hydrogen pressure at time of test (if applicable) ______________

Date that data shown in last verification column in table above was taken ______________

Appendix A



NOTE:

* POSITIVE NUMBERS INDICATE POWER FLOW IN DIRECTION OF ARROW, NEGATIVE NUMBERS INDICATE POWER FLOW IN OPPOSITE DIRECTION OF ARROW.

+ LOAD ONLY ACTIVE DURING UNIT START UP.

NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	REFERENCE DWG'S

TRI-STATE Generation and Transmission Association, Inc.

BURLINGTON GENERATING STATION
SIMPLIFIED ONE-LINE DIAGRAMS
FOR NERC STANDARD MOD-025-2

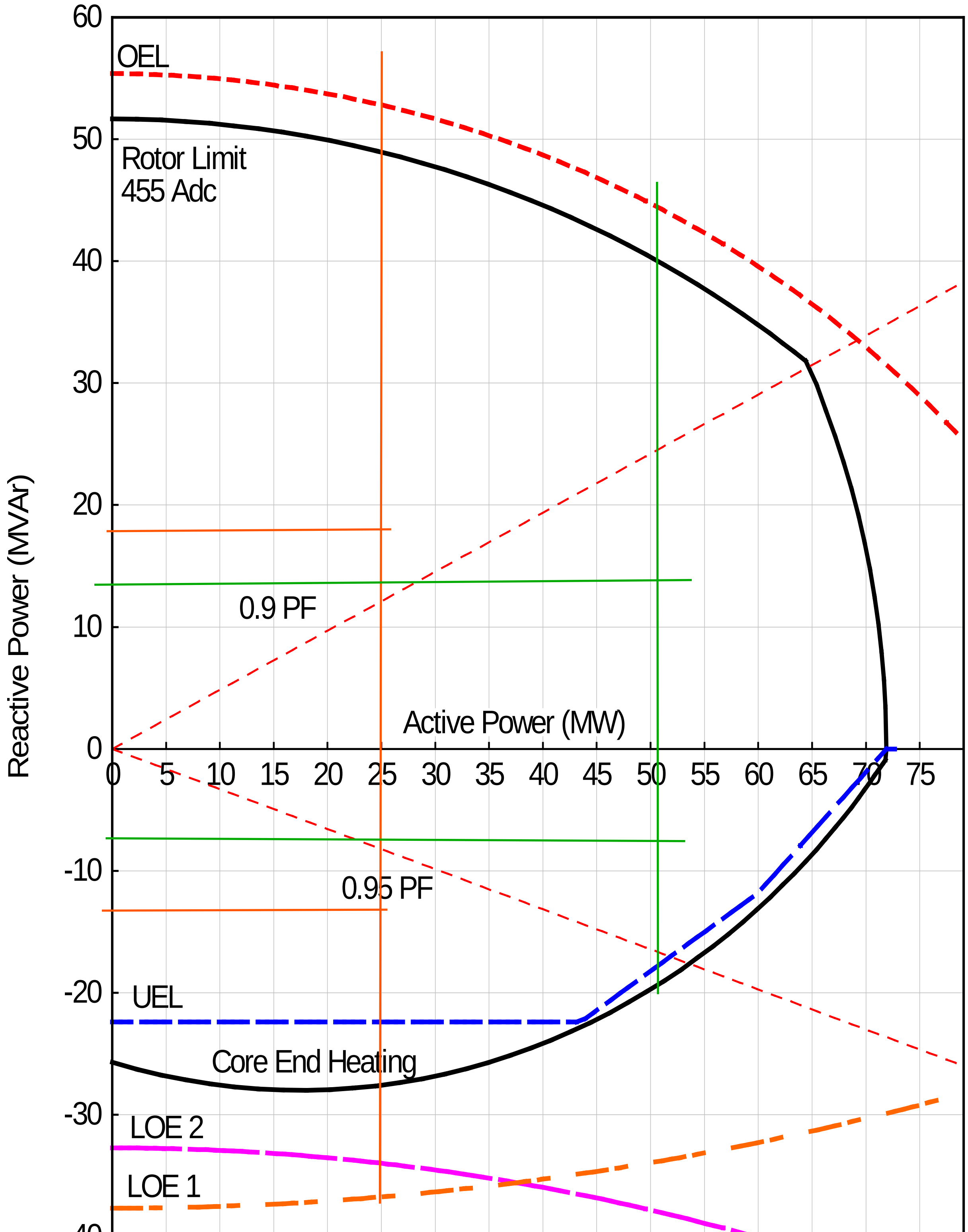
VENDOR NAME
VENDOR DWG. NUMBER
CONTRACT NUMBER
ORDER NUMBER

DWN.	BARBARA HERRERA	SCALE	NTS
CH'K'D.	DAVE READIO	DATE	08-06-15
APPR.			

DWG. NO. 0029-064-02-0002 SHEET 1 REV. 0

MERIDIAN (A) 08-06-15 (BJH)

B2 Unofficial Calculated Generator Capability Curve



Testing Data
Tri-State Generation and Transmission Association
Burlington Generating Station
Unit #1

Date: (MM/DD/YY) 04/22/18

At MINIMUM LOAD and MAXIMUM LEADING vars:

Time at start of Test (HH:MM): 1505 Time at end of Test (HH:MM): 1510

Air Temperature: 54 (°F) Humidity: 48 %

Gross Real Output: 25.3 (MW)

Gross Reactive Output: -13.85 (Mvar)

Net Real Output: 24.7 (MW)

Net Reactive Output: -15.2 (Mvar)

Station Service Real: 126.12 (~~M~~kW)

Station Service Reactive: 98.06 (~~M~~kvar)

Voltage of 480 V Bus: 13.32 (V)

Generator Bus (13.8 kV) Voltage Phase AB (SEL-735): 13.32 (kV)

Generator Bus (13.8 kV) Voltage Phase BC (SEL-735): 13.29 (kV)

Generator Bus (13.8 kV) Voltage Phase CA (SEL-735): 13.34 (kV)

High Side GSU (115 kV) Voltage Phase AB (SEL-735): 118.74 (kV)

High Side GSU (115 kV) Voltage Phase BC (SEL-735): 118.6 (kV)

High Side GSU (115 kV) Voltage Phase CA (SEL-735): 119.0 (kV)

CT34 Current (50/51 AT2-U1-SEL-551C AT2: IA): 6 (A)

CT35 Current (50/51 AT2-U1-SEL-551C AT2: IB): 7 (A)

CT36 Current (50/51 AT2-U1-SEL-551C AT2: IC): 7 (A)

Unit remained on-line?: ☒- YES, ☐- NO

Testing Data
Tri-State Generation and Transmission Association
Burlington Generating Station
Unit #1

Date: (MM/DD/YY) 04/22/18

At MINIMUM LOAD and MAXIMUM LAGGING vars:

Time at start of Test (HH:MM): 1520 Time at end of Test (HH:MM): 1525

Air Temperature: 54 (°F) Humidity: 48 %

Gross Real Output: 24.5 (MW)

Gross Reactive Output: 18.43 (Mvar)

Net Real Output: 24.4 (MW)

Net Reactive Output: 17.2 (Mvar)

Station Service Real: 126.3 (~~M~~ kW)

Station Service Reactive: 116.5 (~~M~~ kvar)

Voltage of 480 V Bus: 14.16 (V)

Generator Bus (13.8 kV) Voltage Phase AB (SEL-735): 14.21 (kV)

Generator Bus (13.8 kV) Voltage Phase BC (SEL-735): 14.10 (kV)

Generator Bus (13.8 kV) Voltage Phase CA (SEL-735): 14.15 (kV)

High Side GSU (115 kV) Voltage Phase AB (SEL-735): 120.46 (kV)

High Side GSU (115 kV) Voltage Phase BC (SEL-735): 120.98 (kV)

High Side GSU (115 kV) Voltage Phase CA (SEL-735): 119.71 (kV)

CT34 Current (50/51 AT2-U1-SEL-551C AT2: IA): 6 (A)

CT35 Current (50/51 AT2-U1-SEL-551C AT2: IB): 7 (A)

CT36 Current (50/51 AT2-U1-SEL-551C AT2: IC): 6 (A)

Unit remained on-line?: ☒ - YES, ☐ - NO

Testing Data
Tri-State Generation and Transmission Association
Burlington Generating Station
Unit #1

Date: (MM/DD/YY) 04/22/18

At MAXIMUM LOAD and MAXIMUM LEADING vars:

Time at start of Test (HH:MM): 1532 Time at end of Test (HH:MM): 1540

Air Temperature: 55 (°F) Humidity: 48 %

Gross Real Output: 51.5 (MW)

Gross Reactive Output: -8.77 (Mvar)

Net Real Output: 51.3 (MW)

Net Reactive Output: -13.5 (Mvar)

Station Service Real: 125.27 (~~M~~kW)

Station Service Reactive: 100.73 (~~M~~kvar)

Voltage of 480 V Bus: 13.37 (kV)

Generator Bus (13.8 kV) Voltage Phase AB (SEL-735): 13.38 (kV)

Generator Bus (13.8 kV) Voltage Phase BC (SEL-735): 13.35 (kV)

Generator Bus (13.8 kV) Voltage Phase CA (SEL-735): 13.32 (kV)

High Side GSU (115 kV) Voltage Phase AB (SEL-735): 119.22 (kV)

High Side GSU (115 kV) Voltage Phase BC (SEL-735): 118.88 (kV)

High Side GSU (115 kV) Voltage Phase CA (SEL-735): 117.89 (kV)

CT34 Current (50/51 AT2-U1-SEL-551C AT2: IA): 6 (A)

CT35 Current (50/51 AT2-U1-SEL-551C AT2: IB): 7 (A)

CT36 Current (50/51 AT2-U1-SEL-551C AT2: IC): 6 (A)

Unit remained on-line?: ☒ - YES, ☐ - NO

Testing Data
Tri-State Generation and Transmission Association
Burlington Generating Station
Unit #1

Date: (MM/DD/YY) ________________

At MAXIMUM LOAD and MAXIMUM LAGGING vars:

Time at start of Test (HH:MM): 1550 Time at end of Test (HH:MM): 1655

Air Temperature: 55 (°F) Humidity: 48 %

Gross Real Output: 52.1 / 51.5 (MW)

Gross Reactive Output: 19.21 (Mvar)

Net Real Output: 51.3 (MW)

Net Reactive Output: 14.18 (Mvar)

Station Service Real: 126.0 (~~M~~kW)

Station Service Reactive: 117.5 (~~M~~kvar)

Voltage of 480 V Bus: 1414 (V)

Generator Bus (13.8 kV) Voltage Phase AB (SEL-735): 14.18 (kV)

Generator Bus (13.8 kV) Voltage Phase BC (SEL-735): 14.12 (kV)

Generator Bus (13.8 kV) Voltage Phase CA (SEL-735): 14.10 (kV)

High Side GSU (115 kV) Voltage Phase AB (SEL-735): 121.07 (kV)

High Side GSU (115 kV) Voltage Phase BC (SEL-735): 120.72 (kV)

High Side GSU (115 kV) Voltage Phase CA (SEL-735): 119.84 (kV)

CT34 Current (50/51 AT2-U1-SEL-551C AT2: IA): 6.68 / 6 (A)

CT35 Current (50/51 AT2-U1-SEL-551C AT2: IB): 7.29 / 7 (A)

CT36 Current (50/51 AT2-U1-SEL-551C AT2: IC): 6.98 / 7 (A)

Unit remained on-line?: ☒ - YES, ☐ - NO

Testing Data
Tri-State Generation and Transmission Association
Burlington Generating Station
Unit #2

Date: (MM/DD/YY) 04/26/18

At MINIMUM LOAD and MAXIMUM LEADING vars:

Time at start of Test (HH:MM): 1806 Time at end of Test (HH:MM): 1925

Air Temperature: 13°c 55 (°F) Humidity: 35.3 .2 %

Gross Real Output: 24.9 (MW)

Gross Reactive Output: -17.29 (Mvar)

Net Real Output: ~~23.0~~ 24.8 (MW)

Net Reactive Output: -19.5 (Mvar)

Station Service Real: 148.25 (MW)

Station Service Reactive: 109.1 (Mvar)

Voltage of 480 V Bus: 13.16 (kV)

Generator Bus (13.8 kV) Voltage Phase AB (SEL-735): 13.17 (kV)

Generator Bus (13.8 kV) Voltage Phase BC (SEL-735): ______ (kV)

Generator Bus (13.8 kV) Voltage Phase CA (SEL-735): ______ (kV)

High Side GSU (115 kV) Voltage Phase AB (SEL-735): 119.25 (kV)

High Side GSU (115 kV) Voltage Phase BC (SEL-735): 118.77 (kV)

High Side GSU (115 kV) Voltage Phase CA (SEL-735): 117.54 (kV)

CT34 Current (50/51 AT2-U2-SEL-551C AT2: IA): 8 (A)

CT35 Current (50/51 AT2-U2-SEL-551C AT2: IB): 8 (A)

CT36 Current (50/51 AT2-U2-SEL-551C AT2: IC): 8 (A)

Unit remained on-line?: ☒ - YES, ☐ - NO

Testing Data
Tri-State Generation and Transmission Association
Burlington Generating Station
Unit #2

Date: (MM/DD/YY) ________________

At MINIMUM LOAD and MAXIMUM LAGGING vars:

Time at start of Test (HH:MM): 1928 Time at end of Test (HH:MM): 1935

Air Temperature: 13 (°F) Humidity: ____ %
-2

Gross Real Output: 25.7 (MW)

Gross Reactive Output: 25.7 (Mvar)

Net Real Output: 25.3 (MW)

Net Reactive Output: 23.4 (Mvar)

Station Service Real: 151.3 (MW)

Station Service Reactive: 141.4 (Mvar)

Voltage of 480 V Bus: 14.3 (V)

Generator Bus (13.8 kV) Voltage Phase AB (SEL-735): 14.36 (kV)

Generator Bus (13.8 kV) Voltage Phase BC (SEL-735): 14.4 (kV)

Generator Bus (13.8 kV) Voltage Phase CA (SEL-735): 14.36 (kV)

High Side GSU (115 kV) Voltage Phase AB (SEL-735): 121.7 (kV)

High Side GSU (115 kV) Voltage Phase BC (SEL-735): 121.0 (kV)

High Side GSU (115 kV) Voltage Phase CA (SEL-735): 120.25 (kV)

CT34 Current (50/51 AT2-U2-SEL-551C AT2: IA): 8 (A)

CT35 Current (50/51 AT2-U2-SEL-551C AT2: IB): 8 (A)

CT36 Current (50/51 AT2-U2-SEL-551C AT2: IC): 8 (A)

Unit remained on-line?: ☒- YES, ☐- NO

Testing Data
Tri-State Generation and Transmission Association
Burlington Generating Station
Unit #2

Date: (MM/DD/YY) 04/26/18

At MAXIMUM LOAD and MAXIMUM LEADING vars:

Time at start of Test (HH:MM): 1945 Time at end of Test (HH:MM): ~~19~~ 2000

Air Temperature: 57 (°F) Humidity: ___ % -2

Gross Real Output: 50.6 (MW)

Gross Reactive Output: -11.2 (Mvar)

Net Real Output: 50.2 (MW)

Net Reactive Output: -16.1 (Mvar)

Station Service Real: 158.2 (MW)

Station Service Reactive: 169.4 (Mvar)

Voltage of 480 V Bus: 13.3 (V)

Generator Bus (13.8 kV) Voltage Phase AB (SEL-735): 13.2 (kV)

Generator Bus (13.8 kV) Voltage Phase BC (SEL-735): 13.3 (kV)

Generator Bus (13.8 kV) Voltage Phase CA (SEL-735): 13.2 (kV)

High Side GSU (115 kV) Voltage Phase AB (SEL-735): 119.0 (kV)

High Side GSU (115 kV) Voltage Phase BC (SEL-735): 118.5 (kV)

High Side GSU (115 kV) Voltage Phase CA (SEL-735): 117.6 (kV)

CT34 Current (50/51 AT2-U2-SEL-551C AT2: IA): 8 (A)

CT35 Current (50/51 AT2-U2-SEL-551C AT2: IB): 8 (A)

CT36 Current (50/51 AT2-U2-SEL-551C AT2: IC): 9 (A)

Unit remained on-line?: ☑ - YES, ☐ - NO

Testing Data
Tri-State Generation and Transmission Association
Burlington Generating Station
Unit #2

Date: (MM/DD/YY) 04/26/18

At MAXIMUM LOAD and MAXIMUM LAGGING vars:

Time at start of Test (HH:MM): 2000 Time at end of Test (HH:MM): 2105

Air Temperature: 53 (°F) Humidity: 30 %

Gross Real Output: 51.1 (MW)

Gross Reactive Output: 19.7 (Mvar)

Stator 58°C

Net Real Output: 50.5 (MW)

Net Reactive Output: 14.6 (Mvar)

Station Service Real: 163.2 (MW)

Station Service Reactive: 133.6 (Mvar)

Voltage of 480 V Bus: 14.2 (V)

Generator Bus (13.8 kV) Voltage Phase AB (SEL-735): 14.16 (kV)

Generator Bus (13.8 kV) Voltage Phase BC (SEL-735): 14.22 (kV)

Generator Bus (13.8 kV) Voltage Phase CA (SEL-735): 14.13 (kV)

High Side GSU (115 kV) Voltage Phase AB (SEL-735): 121.0 (kV)

High Side GSU (115 kV) Voltage Phase BC (SEL-735): 120.5 (kV)

High Side GSU (115 kV) Voltage Phase CA (SEL-735): 119.6 (kV)

CT34 Current (50/51 AT2-U2-SEL-551C AT2: IA): 8 (A)

CT35 Current (50/51 AT2-U2-SEL-551C AT2: IB): 8 (A)

CT36 Current (50/51 AT2-U2-SEL-551C AT2: IC): 9 (A)

Unit remained on-line?: ☒- YES, ☐- NO

Testing Data
Tri-State Generation and Transmission Association
Burlington Generating Station

Name of Person Performing Test: David Reading

Signature: David Reading

Operational limitations (if any): ______________________________

____

Exhibit No. TS-023

Craig Unit 1

MOD-025 Test Reports and Capability Curves

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

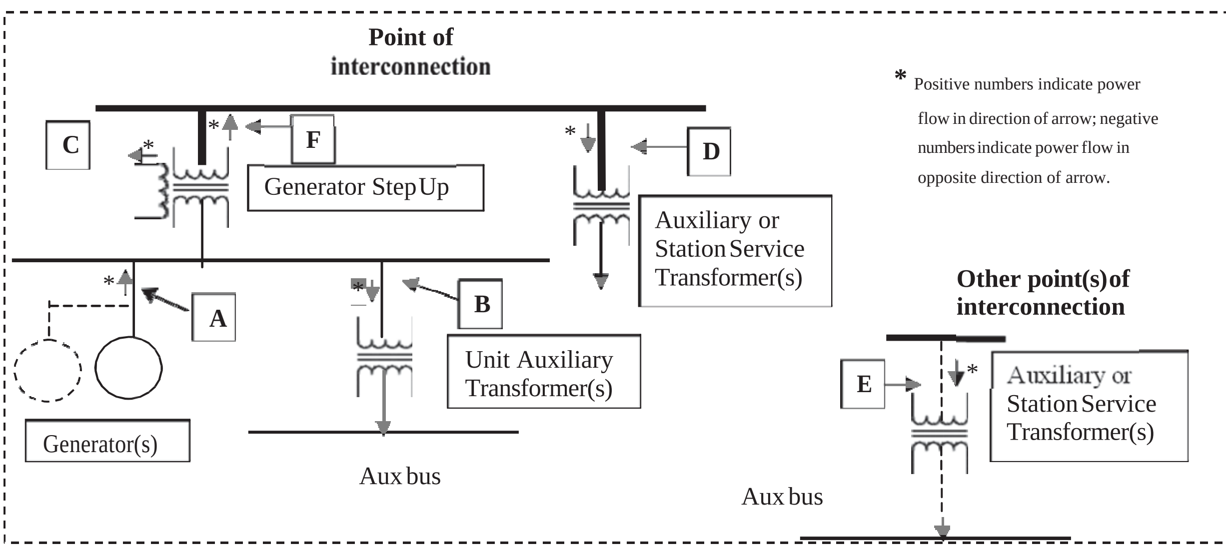
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: Craig Generating Station **Unit: 1** **Date of Report: 06/24/2019**

Check all that apply:

- [x] Over-excited Full Load Reactive Power Verification
- [x] Under-excited Full Load Reactive Power Verification
- [x] Over-excited Minimum Load Reactive Power Verification
- [x] Under-excited Minimum Load Reactive Power Verification
- [x] Real Power Verification
- [x] Staged Test Data
- [ ] Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**21.1kV**	**192.0 MW**	**-83.7 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**21.1 kV**	**19.42 MW**	**17.35 Mvar**	Unit Auxiliary Transformer
B2	**21.1 kV**	**3.54 MW**	**3.97 Mvar**	Reserve Auxiliary ransformer
B	**21.1 kV**	**22.96 MW**	**21.32 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2				
F	**239.5 kV**	**166.1 MW**	**-121.27 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**23.66 kV**	**195.0 MW**	**166.83 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**23.66 kV**	**20.5 MW**	**22.76 Mvar**	Unit Auxiliary Transformer
B2	**23.66 kV**	**3.64 MW**	**5.43 Mvar**	Reserve Auxiliary Transformer
B	**23.66 kV**	**24.14 MW**	**28.19 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2				
F	**248.8 kV**	**167.68 MW**	**118.59 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**20.9 kV**	**430.0 MW**	**-62.0 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**20.9 kV**	**28.4 MW**	**21.6 Mvar**	Unit Auxiliary Transformer
B2	**20.9 kV**	**5.6 MW**	**4.7 Mvar**	Reserve Auxiliary Transformer
B	**20.9 kV**	**34.0 MW**	**26.3 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2				
F	**239.0 kV**	**393.0 MW**	**-126 Mvar**	Net unit capability
Identify calculated values, if any: F Mvars calculated based on GSU impedance losses				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**23.5 kV**	**428 MW**	**228 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**23.5 kV**	**28.1 MW**	**26.2 Mvar**	Unit Auxiliary Transformer
B2	**23.5 kV**	**5.9 MW**	**6.0 Mvar**	Reserve Auxiliary Transformer
B	**23.5 kV**	**34.0 MW**	**32.2Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2				
F	**246.0 kV**	**391.0 MW**	**135.0 Mvar**	Net unit capability
Identify calculated values, if any: : F Mvars calculated based on GSU impedance losses				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability(Mvar)	-83.7	
GSU Reactive Power (Mvar)	-37.7	
Net Leading Reactive Power Capability (Mvar)	-125	
Gross Lagging Reactive Power Capability (Mvar)	228	
GSU Lagging Reactive Power (Mvar)	-60.8	
Net Lagging Reactive Power Capability (Mvar)	135	
Gross Real Power Capability Minimum Stable Load (MW)	195	
Gross Real Power Capability Maximum output (MW)	430	
Station Service Reactive Load (Mvar)	32.2	
Station Service Real Load (MW)	34.0	
Net Unit Maximum Real Power Output (MW)	394	
GSU Real Power Losses (MW)	3.1	
GSU Reactive Losses (Mvar)	-60.8	

Summary of Verification

- Date of Verification: 06/03/2019 and 06/13/2019
- Verification Start Time: 02:10 and 10:36
- Verification End Time: 03:00 and 13:02
- Scheduled Voltage: 240 kV
- Transformer Voltage Ratio:
  - GSU: 16.429
  - Unit Aux : 3.043
  - Res Aux: 3.043
- Transformer Tap Setting:
  - GSU: 4
  - Unit Aux: 3
  - Res Aux: 3

- Ambient conditions at the end of the verification:
    - Air temperature: 48^o F and 64^o F
    - Humidity: 81.5% and 45 %

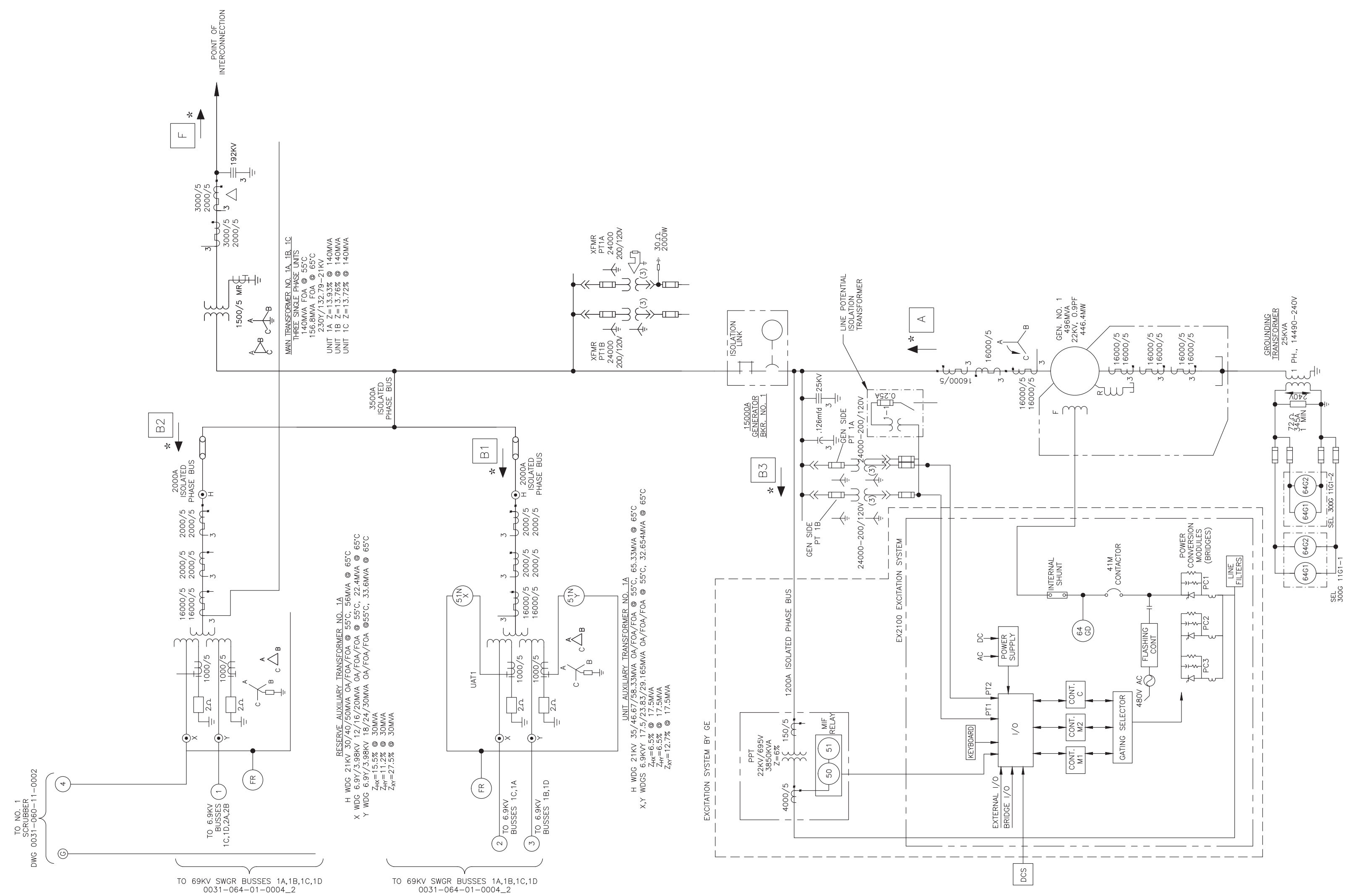
Date that data shown in last verification column in table above was taken: 06/13/2019

Remarks :

Limiting factor was the 6.9 kV auxiliary bus Voltage. During low load maximum lagging test limiting factor was 240 kV transmission system Voltage became too high.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

Appendix A



NOTE:

* POSITIVE NUMBERS INDICATE POWER FLOW IN DIRECTION OF ARROW, NEGATIVE NUMBERS INDICATE POWER FLOW IN OPPOSITE OF ARROW.

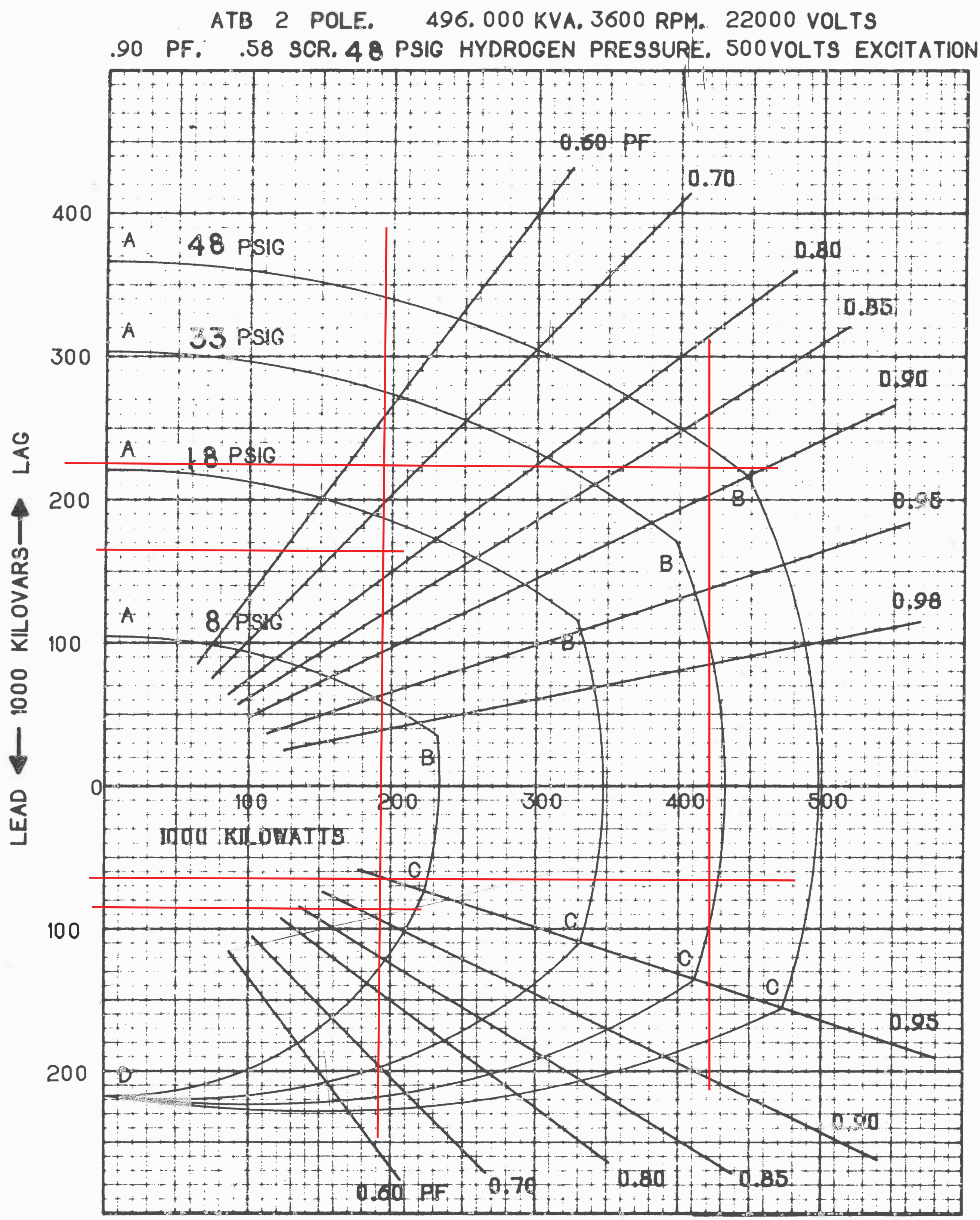
NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	REFERENCE DWG'S

TRI-STATE Generation and Transmission Association, Inc.

VENDOR NAME
VENDOR DWG. NUMBER
CONTRACT NUMBER
ORDER NUMBER

CRAIG STATION UNIT 1
SIMPLIFIED ONE–LINE DIAGRAM
FOR NERC STANDARD MOD–026

DWN.	BARBARA HERRERA	SCALE	NTS	DWG. NO.	SHEET	REV.
CHK'D.	DAVE READIO	DATE	12-28-15	0031-064-01-1380	1	0
APPR.						



CURVE AB LIMITED BY FIELD HEATING
CURVE BC LIMITED BY ARMATURE HEATING
CURVE CD LIMITED BY ARMATURE CORE END HEATING

Estimated capability curves
Dwg. 435HA490 (rev 1)

Fig. 17-3

Testing Data
Tri-State Generation and Transmission Association
Craig Generating Station

Minimal Stable load Data:

Date: (MM/DD/YY) 06/03/19 **Unit:** 1

Time at start of Test (HH:MM): 02:10

Time at end of Test (HH:MM): 03:00

Air Temperature: 09 **(°C)** **Humidity:** 81.5 **%**

Stator Cooling Water Temperature: 40.3 **(°C)**

Hydrogen Pressure: 47.0 **psi**

At minimum stable load (Raising Generator Terminal Voltage):

Real Output of Generator: 192.0 **(MW)**

High Side (System) Voltage: 248.8 **(kV)**

Low Side (Generator) Voltage: 23.7 **(kV)**

Maximum lagging reactive power: 166.8 **(MVAR)**

Station Service real power load (Unit Aux): 20.5 **(MW)**

Station Service reactive power load (Unit Aux): 22.8 **(MVAR)**

Station Service real power load (Res Aux): 3.6 **(MW)**

Station Service reactive power load (Res Aux): 5.4 **(MVAR)**

Real Power output of GSU transformers: 167.7 **(MW)**

Reactive Power output of GSU Transformers: 118.6 **(MVAR)**

Exciter Voltage: 301 **(V)**

Exciter Current: 2396 **(A)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

6.9 kV Bus Voltage: 7.58 **(kV)**

Transmission system voltage too high

At minimum stable load (Lower Generator Terminal Voltage):

Real Output of Generator: 192.0 **(MW)**

High Side (System) Voltage: 239.5 **(kV)**

Low Side (Generator) Voltage: 21.1 **(kV)**

Maximum leading reactive power: -83.7 **(MVAR)**

Station Service real power load (Unit Aux): 19.4 **(MW)**

Station Service reactive power load (Unit Aux): 17.4 **(MVAR)**

Station Service real power load (Res Aux): 3.5 **(MW)**

Station Service reactive power load (Res Aux): 4.0 **(MVAR)**

Real Power output of GSU transformers: 166.1 **(MW)**

Reactive Power output of GSU Transformers: -122.3 **(MVAR)**

Exciter Voltage: 157 **(V)**

Exciter Current: 1205 **(A)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

6.9 kV Bus Voltage: 6.28 **(kV)**

Maximum Out level Data

Date: (MM/DD/YY) 06/13/19 **Unit:** 1

Time at start of Test (HH:MM): 10:36

Time at end of Test (HH:MM): 13:02

Air Temperature: 64 **(°F)** **Humidity:** 45 **%**

Stator Cooling Water Temperature: 45.0 **(°C)**

Hydrogen Pressure: 48.1 **psi**

At maximum stable load (Lowering Terminal Voltage):

Real Output of Generator: 430 **(MW)**

High Side (System) Voltage: 239 **(kV)**

Low Side (Generator) Voltage: 20.9 **(kV)**

Maximum leading reactive power: -62 **(MVAR)**

Station Service real power load (Unit Aux): 28.4 **(MW)**

Station Service reactive power load (Unit Aux): 21.6 **(MVAR)**

Station Service real power load (Res Aux): 5.6 **(MW)**

Station Service reactive power load (Res Aux): 4.7 **(MVAR)**

Real Power output of GSU transformers: 393 **(MW)**

Reactive Power output of GSU Transformers: ________________ **(MVAR)**

Exciter Voltage: 273 **(V)**

Exciter Current: 2103 **(A)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

6.9 kV Bus Voltage: 6.53 **(kV)**

At maximum stable load (Raising Generator Terminal Voltage):

Real Output of Generator: 430 / 426 **(MW)**

High Side (System) Voltage: 246 **(kV)**

Low Side (Generator) Voltage: 23.5 / 23.5 **(kV)**

Maximum lagging reactive power: 220 / 236 **(MVAR)**

Station Service real power load (Unit Aux): 28.1 / 28.1 **(MW)**

Station Service reactive power load (Unit Aux): 26.2 / 26.1 **(MVAR)**

Station Service real power load (Res Aux): 5.9 / 5.8 **(MW)**

Station Service reactive power load (Res Aux): 6.0 / 5.9 **(MVAR)**

Real Power output of GSU transformers: 393 **(MW)**

Reactive Power output of GSU Transformers: ________________ **(MVAR)**

Exciter Voltage: 415 / 420 **(V)**

Exciter Current: 3082 / 3112 **(A)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

6.9 kV Bus Voltage: 7.3 / 7.3 **(kV)**

Generator Stator Cooling water Temperature at end of test: 48.0 **(^oC)**

Name of Person Performing Test: David Readio and Steve Wisniewski

Signature: [signature]

Exhibit No. TS-023

Craig Unit 2

MOD-025 Test Reports and Capability Curves

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

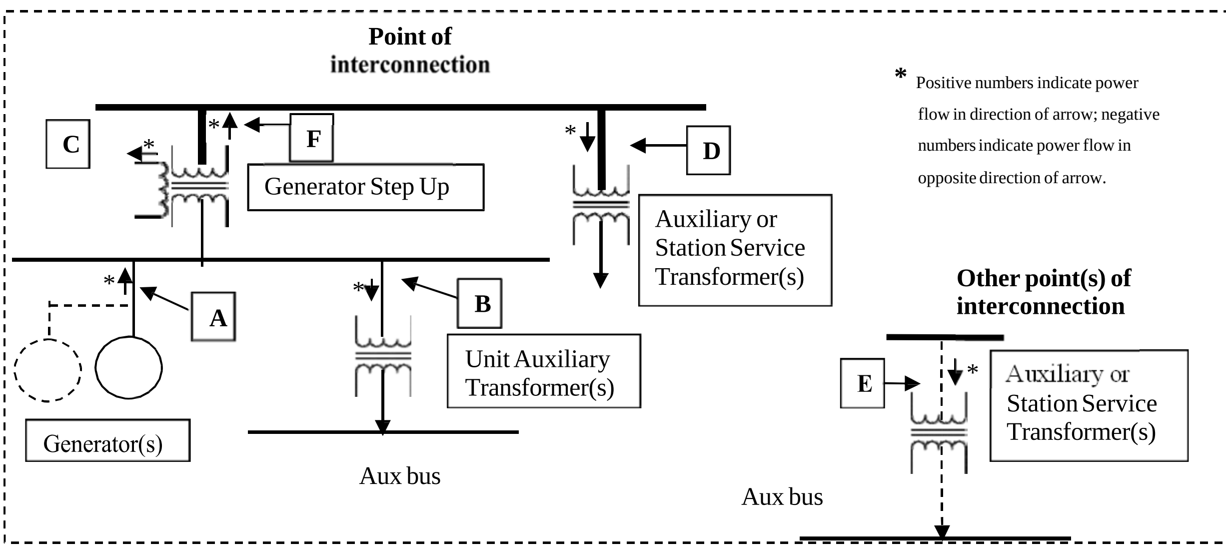
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: Craig Generating Station **Unit: 2** **Date of Report: 04/25/2019**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**21.2 kV**	**152.7 MW**	**-69.5 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**21.2 kV**	**15.8 MW**	**15.6 Mvar**	Unit Auxiliary Transformer
B2	**21.2 kV**	**3.86 MW**	**4.2 Mvar**	Reserve Auxiliary ransformer
B3	**21.2 kV**	**0.15 MW**	**0.0 Mvar**	Exciter PPTs
B	**21.2 kV**	**19.81 MW**	**19.8 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2 + B3; B3=V*I from exciter				
F	**239.1 kV**	**129.5 MW**	**-102.2 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**23.8 kV**	**153 MW**	**265.9 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**23.8 kV**	**16.23 MW**	**21.21 Mvar**	Unit Auxiliary Transformer
B2	**23.8 kV**	**3.96 MW**	**5.7 Mvar**	Reserve Auxiliary Transformer
B3	**23.8 kV**	**1.04 MW**	**0.0 Mvar**	Exciter PPTs
B	**23.8 kV**	**21.23 MW**	**26.91 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2 + B3; B3=V*I from exciter				
F	**245.1 kV**	**133.5 MW**	**212.2 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**21.08 kV**	**442 MW**	**-21.1 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**21.08 kV**	**22.7 MW**	**19.1 Mvar**	Unit Auxiliary Transformer
B2	**21.08 kV**	**6.89 MW**	**4.88 Mvar**	Reserve Auxiliary Transformer
B3	**21.08 kV**	**0.63 MW**	**0.0 Mvar**	Exciter PPTs
B	**21.08 kV**	**30.22 MW**	**23.98 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2 + B3; B3=V*I from exciter				
F	**356.8 kV**	**407.2 MW**	**-104.9 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**22.86 kV**	**440 MW**	**183 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**22.86 kV**	**23.09 MW**	**22.1 Mvar**	Unit Auxiliary Transformer
B2	**22.86 kV**	**6.87 MW**	**5.67 Mvar**	Reserve Auxiliary Transformer
B3	**22.86 kV**	**1.1 MW**	**0.0 Mvar**	Exciter PPTs
B	**22.86 kV**	**31.06 MW**	**27.77 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2 + B3; B3=V*I from exciter				
F	**240.7 kV**	**409.5 MW**	**90.92 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-69.5	
GSU Reactive Power (Mvar)	-35.4	
Net Leading Reactive Power Capability (Mvar)	-104.9	
Gross Lagging Reactive Power Capability (Mvar)	183.0	
GSU Lagging Reactive Power (Mvar)	-92.1	
Net Lagging Reactive Power Capability (Mvar)	90.9	
Gross Real Power Capability Minimum Stable Load (MW)	153.0	
Gross Real Power Capability Maximum output (MW)	442.0	
Station Service Reactive Load (Mvar)	27.8	
Station Service Real Load (MW)	31.0	
Net Unit Maximum Real Power Output (MW)	409.5	
GSU Real Power Losses (MW)	1.5	
GSU Reactive Losses (Mvar)	64.3	

Summary of Verification

- Date of Verification (minimum load) : 04/23/2019 Date of Verification (max load) : 04/24/2019
- Verification Start Time: 11:30 Verification Start Time: 07:48
- Verification End Time: 12:16 Verification End Time: 09:30
- Scheduled Voltage: 2 4 0 kV Scheduled Voltage: 2 3 7 kV
- Transformer Voltage Ratio:
  - GSU: 10.925
  - Unit Aux : 3.043
  - Res Aux: 3.043
- Transformer Tap Setting:
  - GSU: 4
  - Unit Aux: 3
  - Res Aux: 3

- Ambient conditions at the end of the verification:
    - Air temperature: 12 ^{o}C 6^{o}C
    - Humidity: 51 % 75.5%

Date that data shown in last verification column in table above was taken: 04/24/2019

Remarks :

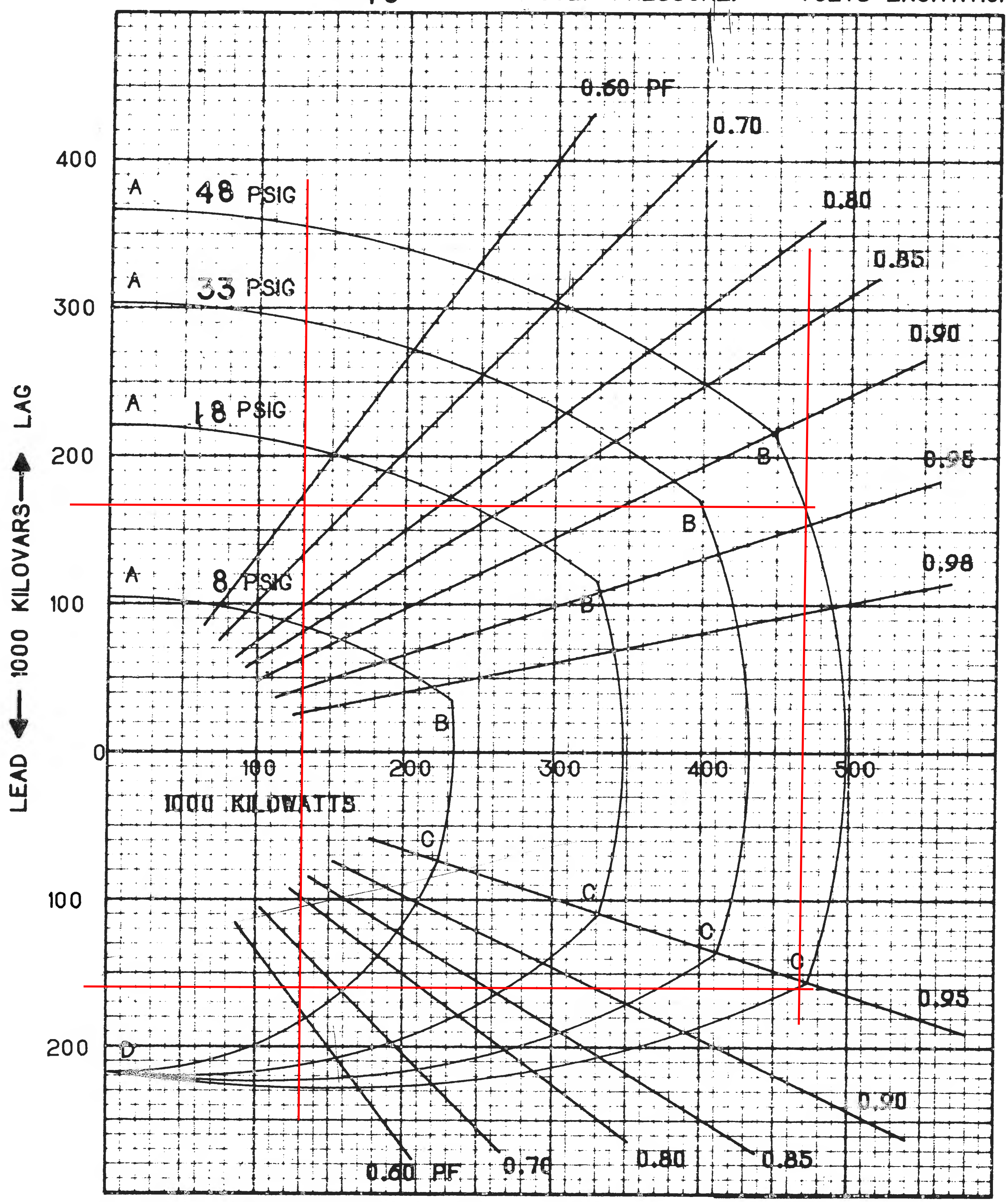
Minimum load testing was conducted on 04/23/2019. Maximum load testing was conducted on 04/24/2019. Limiting factor was the 6.9 kV auxiliary bus voltage becoming too low. OEL and UEL did come in during the maximum load testing.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

Appendix A


TO 6.9KV SWGR BUSSES 2A,2B,2C,2D 0032-064-01-0003_2
TO 6.9KV BUSSES 1A,1B,2B,2D
FR
1000/5
2Ω
16000/5
2000/5
2000A ISOLATED PHASE BUS
B2
F
3000/5
2000/5
POINT OF INTERCONNECTION
1500/5 MR
192KV
RESERVE AUXILIARY TRANSFORMER NO. 2A
H WDG 21KV 30/40/50MVA OA/FOA/FOA @ 55°C, 56MVA @ 65°C
X WDG 6.9Y/3.98KV 12/16/20MVA OA/FOA/FOA @ 55°C, 22.4MVA @ 65°C
Y WDG 6.9Y/3.98KV 18/24/30MVA OA/FOA/FOA @55°C, 33.6MVA @ 65°C
Z_{HX}=15.5% @ 30MVA
Z_{HY}=11.2% @ 30MVA
Z_{XY}=27.5% @ 30MVA
MAIN TRANSFORMER NO. 2A, 2B, 2C
THREE SINGLE PHASE UNITS
140MVA FOA @ 55°C
156.8MVA FOA @ 65°C
230Y/132.79–21KV
UNIT 2A Z=13.93% @ 140MVA
UNIT 2B Z=13.76% @ 140MVA
UNIT 2C Z=13.72% @ 140MVA
3500A ISOLATED PHASE BUS
TO 6.9KV BUSSES 2C,2A
TO 6.9KV BUSSES 2B,2D
51N X
51N Y
B1
UNIT AUXILIARY TRANSFORMER NO. 2A
H WDG 21KV 35/46.67/58.33MVA OA/FOA/FOA @ 55°C, 65.33MVA @ 65°C
X,Y WDGS 6.9KVY 17.5/23.83/29.165MVA OA/FOA/FOA @ 55°C, 32.654MVA @ 65°C
Z_{HX}=6.5% @ 17.5MVA
Z_{HY}=6.5% @ 17.5MVA
Z_{XY}=12.7% @ 17.5MVA
XFMR PT2B 24000 200/120V
XFMR PT2A 24000 200/120V
30Ω 2000W
EXCITATION SYSTEM BY GE
PPT 22KV/695V 3850KVA Z=6%
4000/5
150/5
1200A ISOLATED PHASE BUS
MIF RELAY
B3
15000A GENERATOR BKR. NO. 2
ISOLATION LINK
GEN SIDE PT 2B
GEN SIDE PT 2A
.126mfd
25KV
24000–200/120V
LINE POTENTIAL ISOLATION TRANSFORMER
0.25A
EX2100 EXCITATION SYSTEM
A
KEYBOARD
EXTERNAL I/O
BRIDGE I/O
DCS
I/O
PT1 PT2
AC DC
POWER SUPPLY
CONT. M1
CONT. M2
CONT. C
GATING SELECTOR
INTERNAL SHUNT
64 GD
41M CONTACTOR
480V AC
FLASHING CONT
POWER CONVERSION MODULES (BRIDGES)
PC3 PC2 PC1
LINE FILTERS
GEN. NO. 2
496MVA
22KV, 0.9PF
446.4MW
GROUNDING TRANSFORMER
25KVA
1 PH., 14490–240V
72Ω 345A 1 MIN
240V
64G1 64G2
SEL 300G 11G2-1
SEL 300G 11G2-2
NOTE:
* POSITIVE NUMBERS INDICATE POWER FLOW IN DIRECTION OF ARROW, NEGATIVE NUMBERS INDICATE POWER FLOW IN OPPOSITE OF ARROW.
NO. DATE REVISION DWN. CHK'D
REFERENCE DWG'S
VENDOR NAME
VENDOR DWG. NUMBER
CONTRACT NUMBER
ORDER NUMBER
TRI-STATE
Generation and Transmission Association, Inc.
DWN. BARBARA HERRERA
CHK'D DAVE READIO
APPR.
SCALE NTS
DATE 07-18-16
CRAIG STATION UNIT 2
SIMPLIFIED ONE-LINE DIAGRAM
FOR NERC STANDARD MOD-025
DWG. NO. 0032-064-01-2088
SHEET 1
REV. 0

ATB 2 POLE. 496. 000 KVA. 3600 RPM. 22000 VOLTS
.90 PF. .58 SCR. 48 PSIG HYDROGEN PRESSURE. 500 VOLTS EXCITATION



CURVE AB LIMITED BY FIELD HEATING
CURVE BC LIMITED BY ARMATURE HEATING
CURVE CD LIMITED BY ARMATURE CORE END HEATING

Estimated capability curves
Dwg. 435HA490 (rev 1)

Fig. 17-3

Testing Data
Tri-State Generation and Transmission Association
Craig Generating Station

Minimal Stable load Data:

Date: (MM/DD/YY) 04/23/2019 **Unit:** 2

Time at start of Test (HH:MM): 11:30

Time at end of Test (HH:MM): 11:45

Air Temperature: 12 **(°C)** **Humidity:** 51 **%**

Stator Cooling Water Temperature: 40.9 **(°C)**

Hydrogen Pressure: 47.7 **psi**

At minimum stable load (Lowering Generator Terminal

Voltage): Real Output of Generator: 152.7 **(MW)**

High Side (System) Voltage: 239.09 **(kV)**

Low Side (Generator) Voltage: 21.2 **(kV)**

Maximum leading reactive power: -69.5 **(MVAR)**

Station Service real power load (Unit Aux): 15.8 **(MW)**

Station Service reactive power load (Unit Aux): 15.6 **(MVAR)**

Station Service real power load (Res Aux): 3.86 **(MW)**

Station Service reactive power load (Res Aux): 4.15 **(MVAR)**

Real Power output of GSU transformers: 129.516 **(MW)**

Reactive Power output of GSU Transformers: -102.194 **(MVAR)**

Exciter Voltage: 134 **(V)**

Exciter Current: 1146 **(A)**

Unit remained on-line?: ☒ **– YES,** ☐ **– NO**

6.9 kV Bus Voltage: 6.540 **(kV)**

Minimal Stable load Data:

Date: (MM/DD/YY)_____04/23/2019______ Unit: _2__________________

Time at start of Test (HH:MM): _11:45_________

Time at end of Test (HH:MM): _12:16_________

Air Temperature:_12____________(°C) Humidity:__51___________%

Stator Cooling Water Temperature: ___40.9________(°C)

Hydrogen Pressure:_47.7_____psi

At minimum stable load (Raise Generator Terminal Voltage):

Real Output of Generator:__153___________(MW)

High Side (System) Voltage:___244.9________(kV)

Low Side (Generator) Voltage:__23.8__________(kV)

Maximum lagging reactive power:_265.9__________(MVAR)

Station Service real power load (Unit Aux):__16.23_________(MW)

Station Service reactive power load (Unit Aux):_21.26__________(MVAR)

Station Service real power load (Res Aux):____3.96_________(MW)

Station Service reactive power load (Res Aux):__5.7___________(MVAR)

Real Power output of GSU transformers:__133.54__________(MW)

Reactive Power output of GSU Transformers:_212.184________(MVAR)

Exciter Voltage:__366______________________(V)

Exciter Current:__2840___________(A)

Unit remained on-line?: ☒ – YES, ☐ – NO

6.9 kV Bus Voltage:__7.502___________________(kV)

Maximum Out level Data

Date: (MM/DD/YY) 04/24/2019 **Unit: 2**

Time at start of Test (HH:MM): 07:48

Time at end of Test (HH:MM): 08:10

Air Temperature: 6 (°C) **Humidity: 75.5 %**

Stator Cooling Water Temperature: 40.2 (°C)

Hydrogen Pressure: 46.8 psi

At maximum stable load (Lowering Terminal Voltage):

Real Output of Generator: 442 (MW)

High Side (System) Voltage: 235.9 (kV)

Low Side (Generator) Voltage: 21.08 (kV)

Maximum leading reactive power: -21.07 (MVAR)

Station Service real power load (Unit Aux): 22.7 (MW)

Station Service reactive power load (Unit Aux): 19.1 (MVAR)

Station Service real power load (Res Aux): 6.89 (MW)

Station Service reactive power load (Res Aux): 4.88 (MVAR)

Real Power output of GSU transformers: 407.2 (MW)

Reactive Power output of GSU Transformers: -104.9 (MVAR)

Exciter Voltage: 281 (V)

Exciter Current: 2255 (A)

Unit remained on-line?: ☒ - YES, ☐ - NO

6.9 kV Bus Voltage: 6.458 (kV)

Maximum Out level Data

Date: (MM/DD/YY) 04/24/2019 **Unit:** 2

Time at start of Test (HH:MM): 08:15

Time at end of Test (HH:MM): 09:30

Air Temperature: 6 **(°C)** **Humidity:** 75.5 **%**

Stator Cooling Water Temperature: 40.2 **(°C)**

Hydrogen Pressure: 46.8 **psi**

At maximum stable load (Raising Terminal Voltage):

Real Output of Generator: 440 **(MW)**

High Side (System) Voltage: 240.7 **(kV)**

Low Side (Generator) Voltage: 22.86 **(kV)**

Maximum lagging reactive power: 183 **(MVAR)**

Station Service real power load (Unit Aux): 23.1 **(MW)**

Station Service reactive power load (Unit Aux): 22.1 **(MVAR)**

Station Service real power load (Res Aux): 6.87 **(MW) Station**

Service reactive power load (Res Aux): 5.67 **(MVAR)**

Real Power output of GSU transformers: 409.5 **(MW) Reactive**

Power output of GSU Transformers: 90.92 **(MVAR)**

Exciter Voltage: 380 **(V)**

Exciter Current: 2900 **(A)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

6.9 kV Bus Voltage: 7.135 **(kV)**

Generator Stator Cooling water Temperature at end of test: 40.3 **(°C)**

Name of Person Performing Test: David Readio

Signature: David G Readio

Exhibit No. TS-023

Craig Unit 3

MOD-025 Test Reports and Capability Curves

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

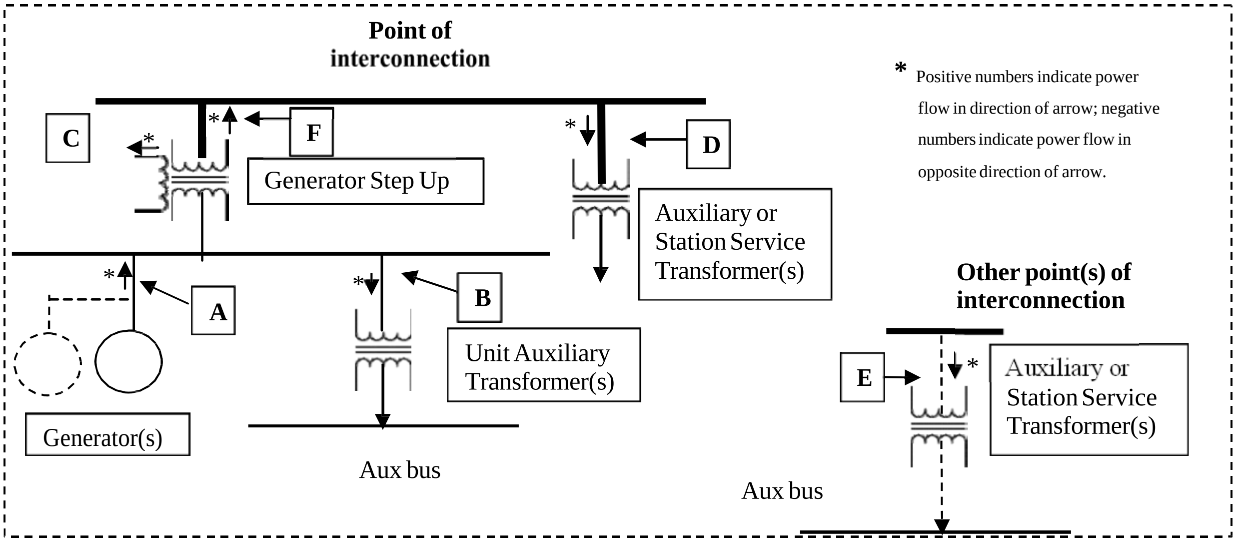
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: Craig Generating Station **Unit: 3** **Date of Report: 06/28/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**21.1 kV**	**168.2 MW**	**-62.47 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**21.1 kV**	**16.72 MW**	**13.09 Mvar**	Unit Auxiliary Transformer
B2	**21.1 kV**	**1.88 MW**	**1.59 Mvar**	Reserve Auxiliary ransformer
B3	**21.1 kV**	**0.0 MW**	**0.0 Mvar**	Reserve Auxiliary Transformer 4A
B	**21.1 kV**	**18.60 MW**	**14.68 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2 + B3				
F	**357.1 kV**	**149.65 MW**	**-91.95 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**22.6 kV**	**163.9 MW**	**93.5 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**22.6 kV**	**16.78 MW**	**15.32 Mvar**	Unit Auxiliary Transformer
B2	**22.6 kV**	**1.53 MW**	**2.01 Mvar**	Reserve Auxiliary Transformer
B3	**22.6 kV**	**0.0 MW**	**0.0 Mvar**	Reserve Auxiliary Transformer 4a
B	**22.6 kV**	**18.31 MW**	**17.33 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2 + B3				
F	**363.0 kV**	**148.58 MW**	**67.43 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**21.08 kV**	**475.0 MW**	**-20.0 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**21.08 kV**	**27.89 MW**	**19.2 Mvar**	Unit Auxiliary Transformer
B2	**21.08 kV**	**1.76 MW**	**1.45 Mvar**	Reserve Auxiliary Transformer
B3	**21.08 kV**	**0.0 MW**	**0.0 Mvar**	Reserve Auxiliary Transformer 4A
B	**21.08 kV**	**29.65 MW**	**20.65 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2 + B3				
F	**356.8 kV**	**448 MW**	**-109.8 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**21.37 kV**	**474 MW**	**116.74 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**21.37 kV**	**28.0 MW**	**20.71 Mvar**	Unit Auxiliary Transformer
B2	**21.37 kV**	**1.85 MW**	**1.85 Mvar**	Reserve Auxiliary Transformer
B3	**21.37 kV**	**0.0 MW**	**0.0 Mvar**	Reserve Auxiliary Transformer 4A
B	**21.37 kV**	**29.85 MW**	**22.56 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2 + B3				
F	**361.6 kV**	**446.1 MW**	**33.1 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-62.47	
GSU Reactive Power (Mvar)	-29.48	
Net Leading Reactive Power Capability (Mvar)	-91.95	
Gross Lagging Reactive Power Capability (Mvar)	116.74	
GSU Lagging Reactive Power (Mvar)	-83.64	
Net Lagging Reactive Power Capability (Mvar)	33.1	
Gross Real Power Capability Minimum Stable Load (MW)	163.9	
Gross Real Power Capability Maximum output (MW)	475.0	
Station Service Reactive Load (Mvar)	22.56	
Station Service Real Load (MW)	29.85	
Net Unit Maximum Real Power Output (MW)	448	
GSU Real Power Losses (MW)	3.35	
GSU Reactive Losses (Mvar)	-61.1	

Summary of Verification

- Date of Verification: 05/04/2016
- Verification Start Time: 20:30
- Verification End Time: 21:45
- Scheduled Voltage: 345 kV
- Transformer Voltage Ratio:
  - GSU: 16.429
  - Unit Aux : 3.043
  - Res Aux: 3.043
- Transformer Tap Setting:
  - GSU: 4
  - Unit Aux: 3
  - Res Aux: 3

- Ambient conditions at the end of the verification:
    - Air temperature: 64 ^{o}F
    - Humidity: 56 %

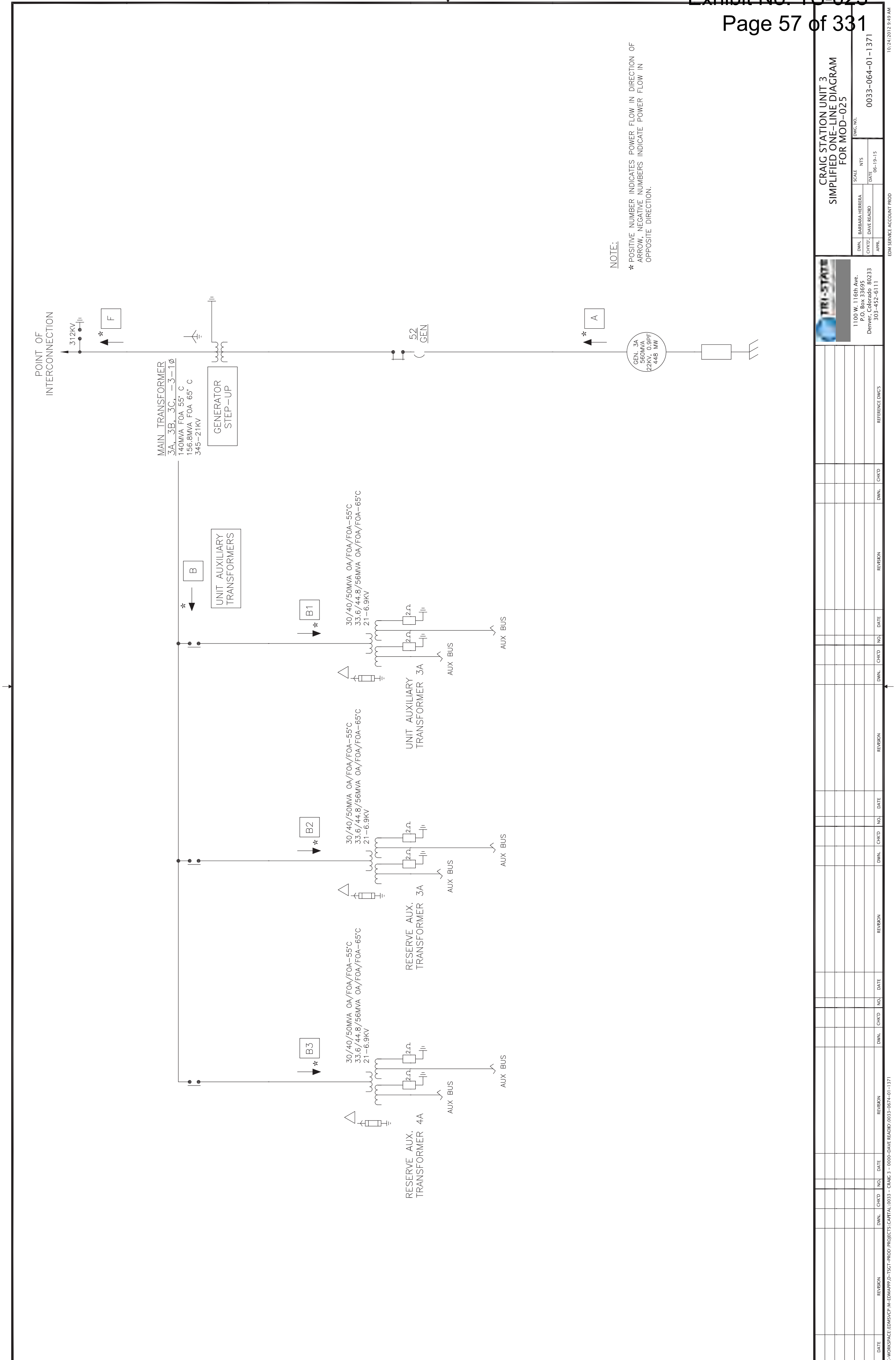
Date that data shown in last verification column in table above was taken: 05/04/2016

Remarks :

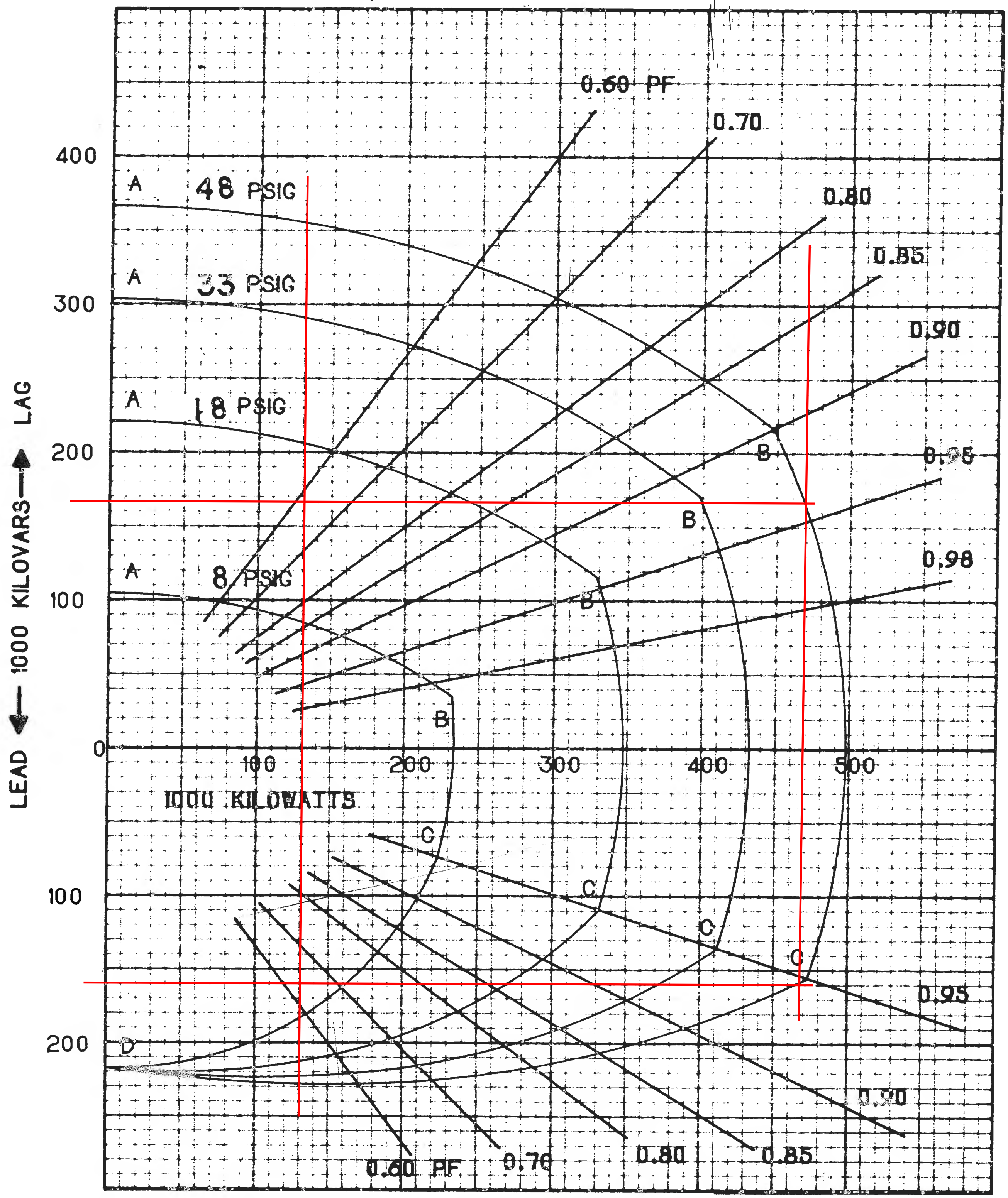
Maximum load testing was conducted on 05/04/2016. Minimum load testing was conducted on 06/11/2016. Limiting factor was the 6.9 kV auxiliary bus voltage.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

Appendix A


CRAIG STATION UNIT 3
SIMPLIFIED ONE-LINE DIAGRAM
FOR MOD-025
DWG. NO. 0033-064-01-1371
SCALE NTS
DATE 06-19-15
DWN. BARBARA HERRERA
CHK'D. DAVE READIO
TRI-STATE
1100 W. 116th Ave.
P.O. Box 33695
Denver, Colorado 80233
303-452-6111
NOTE:
* POSITIVE NUMBER INDICATES POWER FLOW IN DIRECTION OF ARROW, NEGATIVE NUMBERS INDICATE POWER FLOW IN OPPOSITE DIRECTION.
POINT OF INTERCONNECTION
312KV
F
MAIN TRANSFORMER
3A, 3B, 3C, -3-1Ø
140MVA FOA 55° C
156.8MVA FOA 65° C
345-21KV
GENERATOR STEP-UP
52 GEN
A
GEN. 3A
560MVA
22KV, 0.9PF
448 MW
B
UNIT AUXILIARY TRANSFORMERS
B1
B2
B3
30/40/50MVA OA/FOA/FOA-55°C
33.6/44.8/56MVA OA/FOA/FOA-65°C
21-6.9KV
2Ω
AUX BUS
UNIT AUXILIARY TRANSFORMER 3A
RESERVE AUX. TRANSFORMER 3A
RESERVE AUX. TRANSFORMER 4A
REFERENCE DWG'S
REVISION
NO. DATE DWN. CHK'D

ATB 2 POLE. 496.000 KVA. 3600 RPM. 22000 VOLTS
.90 PF. .58 SCR. 48 PSIG HYDROGEN PRESSURE. 500 VOLTS EXCITATION



CURVE AB LIMITED BY FIELD HEATING
CURVE BC LIMITED BY ARMATURE HEATING
CURVE CD LIMITED BY ARMATURE CORE END HEATING

Estimated capability curves
Dwg. 435HA490 (rev 1)

Fig. 17-3

Testing Data
Tri-State Generation and Transmission Association
Craig Generating Station

Minimal Stable load Data:

Date: (MM/DD/YY) 06/11/2016 **Unit:** 3

Time at start of Test (HH:MM): 22:10

Time at end of Test (HH:MM): 23:00

Air Temperature: 64 **(^{o}F)** **Humidity:** 56 **%**

Stator Cooling Water Temperature: 106.5 **(^{o}F)**

Hydrogen Pressure: 47.5 **psi**

At minimum stable load (Raising Generator Terminal Voltage):

Real Output of Generator: 163.9 **(MW)**

High Side (System) Voltage: 363.0 **(kV)**

Low Side (Generator) Voltage: 22.6 **(kV)**

Maximum lagging reactive power: 93.5 **(MVAR)**

Station Service real power load (Unit Aux): 16.78 **(MW)**

Station Service reactive power load (Unit Aux): 15.32 **(MVAR)**

Station Service real power load (Res Aux): 1.53 **(MW)**

Station Service reactive power load (Res Aux): 2.01 **(MVAR)**

Real Power output of GSU transformers: 148.58 **(MW)**

Reactive Power output of GSU Transformers: - 67.43 **(MVAR)**

Exciter Voltage: 221.87 **(V)**

Exciter Current: 1891.04 **(A)**

Unit remained on-line?: ☒**- YES,** ☐**- NO**
6.9 kV Bus Voltage: 7.15 **(kV)**

At minimum stable load (Lower Generator Terminal Voltage):

Real Output of Generator: 168.2 **(MW)**

High Side (System) Voltage: 357.1 **(kV)**

Low Side (Generator) Voltage: 21.1 **(kV)**

Maximum leading reactive power: -62.47 **(MVAR)**

Station Service real power load (Unit Aux): 16.72 **(MW)**

Station Service reactive power load (Unit Aux): 13.09 **(MVAR)**

Station Service real power load (Res Aux): 1.88 **(MW)**

Station Service reactive power load (Res Aux): 1.59 **(MVAR)**

Real Power output of GSU transformers: 149.65 **(MW)**

Reactive Power output of GSU Transformers: -91.95 **(MVAR)**

Exciter Voltage: 158.79 **(V)**

Exciter Current: 1281.98 **(A)**

Unit remained on-line?: ☒**- YES,** ☐**- NO**

6.9 kV Bus Voltage: 6.67 **(kV)**

Maximum Out level Data

Date: (MM/DD/YY) 05/04/2016 **Unit:** 3

Time at start of Test (HH:MM): 20:30

Time at end of Test (HH:MM): 21:45

Air Temperature: 64.3 **(°F)** **Humidity:** 41 **%**

Stator Cooling Water Temperature: 124.72 **(°F)**

Hydrogen Pressure: 47.5 **psi**

At maximum stable load (Lowering Terminal Voltage):

Real Output of Generator: 475 **(MW)**

High Side (System) Voltage: 356.8 **(kV)**

Low Side (Generator) Voltage: 21.08 **(kV)**

Maximum leading reactive power: -20.0 **(MVAR)**

Station Service real power load (Unit Aux): 27.89 **(MW)**

Station Service reactive power load (Unit Aux): 19.2 **(MVAR)**

Station Service real power load (Res Aux): 1.76 **(MW)**

Station Service reactive power load (Res Aux): 1.45 **(MVAR)**

Real Power output of GSU transformers: 448 **(MW)**

Reactive Power output of GSU Transformers: -109.8 **(MVAR)**

Exciter Voltage: 318.94 **(V)**

Exciter Current: 2453.88 **(A)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

6.9 kV Bus Voltage: 6.62 **(kV)**

At maximum stable load (Raising Generator Terminal Voltage):

Real Output of Generator: 474 **(MW)**

High Side (System) Voltage: 361.6 **(kV)**

Low Side (Generator) Voltage: 21.37 **(kV)**

Maximum lagging reactive power: 116.74 **(MVAR)**

Station Service real power load (Unit Aux): 28.00 **(MW)**

Station Service reactive power load (Unit Aux): 20.71 **(MVAR)**

Station Service real power load (Res Aux): 1.85 **(MW)**

Station Service reactive power load (Res Aux): 1.85 **(MVAR)**

Real Power output of GSU transformers: 446.1 **(MW)**

Reactive Power output of GSU Transformers: 33.1 **(MVAR)**

Exciter Voltage: 358.67 **(V)**

Exciter Current: 2727.15 **(A)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

6.9 kV Bus Voltage: 7.25 **(kV)**

Generator Stator Cooling water Temperature at end of test: 123.5 **(^{o}F)**

Name of Person Performing Test: David Readio

Signature: ______________________________

Exhibit No. TS-023

Escalante

MOD-025 Test Reports and Capability Curves

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

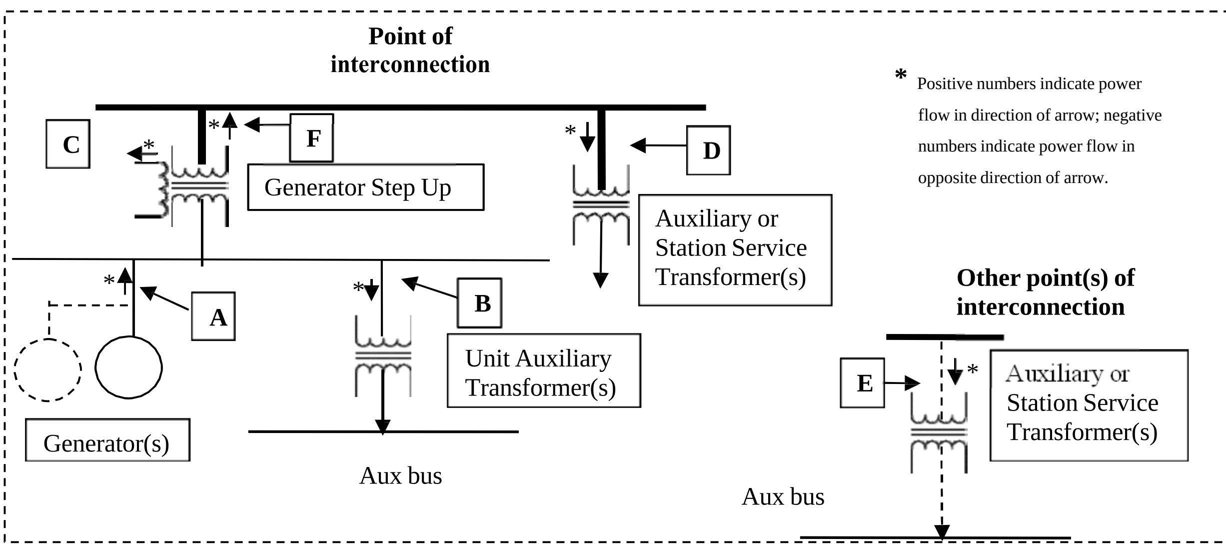
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: Escalante Generating Station **Unit: #1** **Date of Report: 05/27/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**17.321 kV**	**102.4 MW**	**-28.8 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**4.0711 kV**	**3.169 MW**	**3.145 Mvar**	Switchgear 4100 load
B2	**4.0612 kV**	**3.322 MW**	**3.316 Mvar**	Switchgear 4150 load
B3	**17.321 kV**	**0.029 MW**	**0.121 Mvar**	Unit auxiliary transformer no-load losses
B4	**17.321 kV**	**0.010 MW**	**0.196 Mvar**	Unit auxiliary transformer load losses
B5	**17.321 kV**	**0.086 MW**	**0.000 Mvar**	Excitation load
B	**17.321 kV**	**6.530 MW**	**6.778 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2 + B3 + B4 + B5				
D1	**115.1 kV**	**0.0345 MW**	**0.1125 Mvar**	Start-up Transformer 10
D2	**115.1 kV**	**0.0345 MW**	**0.1125 Mvar**	Start-up Transformer 15
D	**115.1 kV**	**0.069 MW**	**0.225 Mvar**	Sum Start-up transformers
Identify calculated values, if any: D=D1 + D2				
F	**230.0 kV**	**91.5 MW**	**-34.95 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**18.529 kV**	**100.1MW**	**42.4 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**4.3526 kV**	**5.420 MW**	**3.745 Mvar**	Switchgear 4100 load
B2	**4.3397 kV**	**5.610 MW**	**3.951 Mvar**	Switchgear 4150 load
B3	**18.529 kV**	**0.034 MW**	**0.169 Mvar**	Unit auxiliary transformer no-load losses
B4	**18.529 kV**	**0.019 MW**	**0.370 Mvar**	Unit auxiliary transformer load losses
B5	**18.529 kV**	**0.174 MW**	**0.000 Mvar**	Excitation load
B	**18.529 kV**	**11.258 MW**	**8.235 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2 + B3 + B4 + B5				
D1	**119.9 kV**	**0.0345 MW**	**0.1125 Mvar**	Start-up Transformer 10
D2	**119.9kV**	**0.0345 MW**	**0.1125 Mvar**	Start-up Transformer 15
D	**119.9 kV**	**0.069 MW**	**0.225 Mvar**	Sum Start-up transformers
Identify calculated values, if any: D=D1 + D2				
F	**240.9 kV**	**88.8 MW**	**34.44 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**17.505 kV**	**269.6 MW**	**-10.62 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**4.096 kV**	**8.090 MW**	**4.283 Mvar**	Switchgear 4100 load
B2	**4.078 kV**	**8.930 MW**	**4.637 Mvar**	Switchgear 4150 load
B3	**17.505 kV**	**0.029 MW**	**0.127 Mvar**	Unit Auxiliary transformer no-load losses
B4	**17.505 kV**	**0.044 MW**	**0.846 Mvar**	Unit auxiliary transformer load losses
B5	**17.505 kV**	**0.314 MW**	**0.000 Mvar**	Exciter load
B	**17.505 kV**	**17.408 MW**	**9.894 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2 + B3 + B4 + B5				
D1	**116.0 kV**	**0.0345 MW**	**0.1125 Mvar**	Start-up Transformer 10
D2	**116.0 kV**	**0.0345 MW**	**0.1125 Mvar**	Start-up Transformer 15
D	**116.0 kV**	**0.069 MW**	**0.225 Mvar**	Sum Start-up transformers
Identify calculated values, if any: D=D1 + D2				
F	**231.9 kV**	**252.6 MW**	**-19.5 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**18.646 kV**	**268.1 MW**	**67.55 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**4.359 kV**	**8.170 MW**	**4.937 Mvar**	Switchgear 4100 load
B2	**4.343 kV**	**8.740 MW**	**5.238 Mvar**	Switchgear 4150 load
B3	**18.646 kV**	**0.034 MW**	**0.174 Mvar**	Unit auxiliary transformer no-load losses
B4	**18.646 kV**	**0.041 MW**	**0.787 Mvar**	Unit auxiliary transformer no-load losses
B5	**18.646 kV**	**0.418 MW**	**0.000 Mvar**	Excitation load
B	**18.646 kV**	**16.989 MW**	**11.136 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: B=B1 + B2 + B3 + B4 + B5; B4 load losses = 62 kW at 22.8 MVA OA 55 deg C rating. B4 MW losses = (B1+B2) UAT MVA load, divided by 22.8 MVA, then adjusted for actual voltage,				
D1	**120.1 kV**	**0.0345 MW**	**0.1125 Mvar**	Start-up Transformer 10
D2	**120.1 kV**	**0.0345 MW**	**0.1125 Mvar**	Start-up Transformer 15
D	**120.1 kV**	**0.069 MW**	**0.225 Mvar**	Sum Start-up transformers
Identify calculated values, if any: D=D1 + D2				
F	**241.0 kV**	**251.2 MW**	**50.0 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-28.80	
GSU Reactive Power (Mvar)	-6.14	
Net Leading Reactive Power Capability (Mvar)	-34.94	
Gross Lagging Reactive Power Capability (Mvar)	67.55	
GSU Lagging Reactive Power (Mvar)	17.55	
Net Lagging Reactive Power Capability (Mvar)	50.00	
Gross Real Power Capability Minimum Stable Load (MW)	100.1	
Gross Real Power Capability Maximum output (MW)	269.6	
Station Service Reactive Load (Mvar)	8.92	
Station Service Real Load (MW)	16.69	
Net Unit Maximum Real Power Output (MW)	252.6	
GSU Real Power Losses (MW)	0.438	
GSU Reactive Losses (Mvar)	-9.777	

Summary of Verification

- Date of Verification: 05/24/2016
- Verification Start Time: 0351 MST
- Verification End Time: 1502 MST
- Scheduled Voltage: 235 kV
- Transformer Voltage Ratio:
  - GSU: 13.32
  - Station Service Transformer: 4.24
  - Start-up Transformer 10: 28.473
  - Start-up Transformer 15: 28.473
- Transformer Tap Setting:
  - GSU: 3

- Station Service Transformer: 3
- Start-up Transformer 10: 2
- Start-up Transformer 15: 2

- Ambient conditions at the end of the verification period:
    - Air temperature:: 72.5 ^{o}F
    - Humidity: 10.89 %
    - Cooling water temperature: 113.0 ^{o}F

Date that data shown in last verification column in table above was taken: 05/24/2016

Remarks :

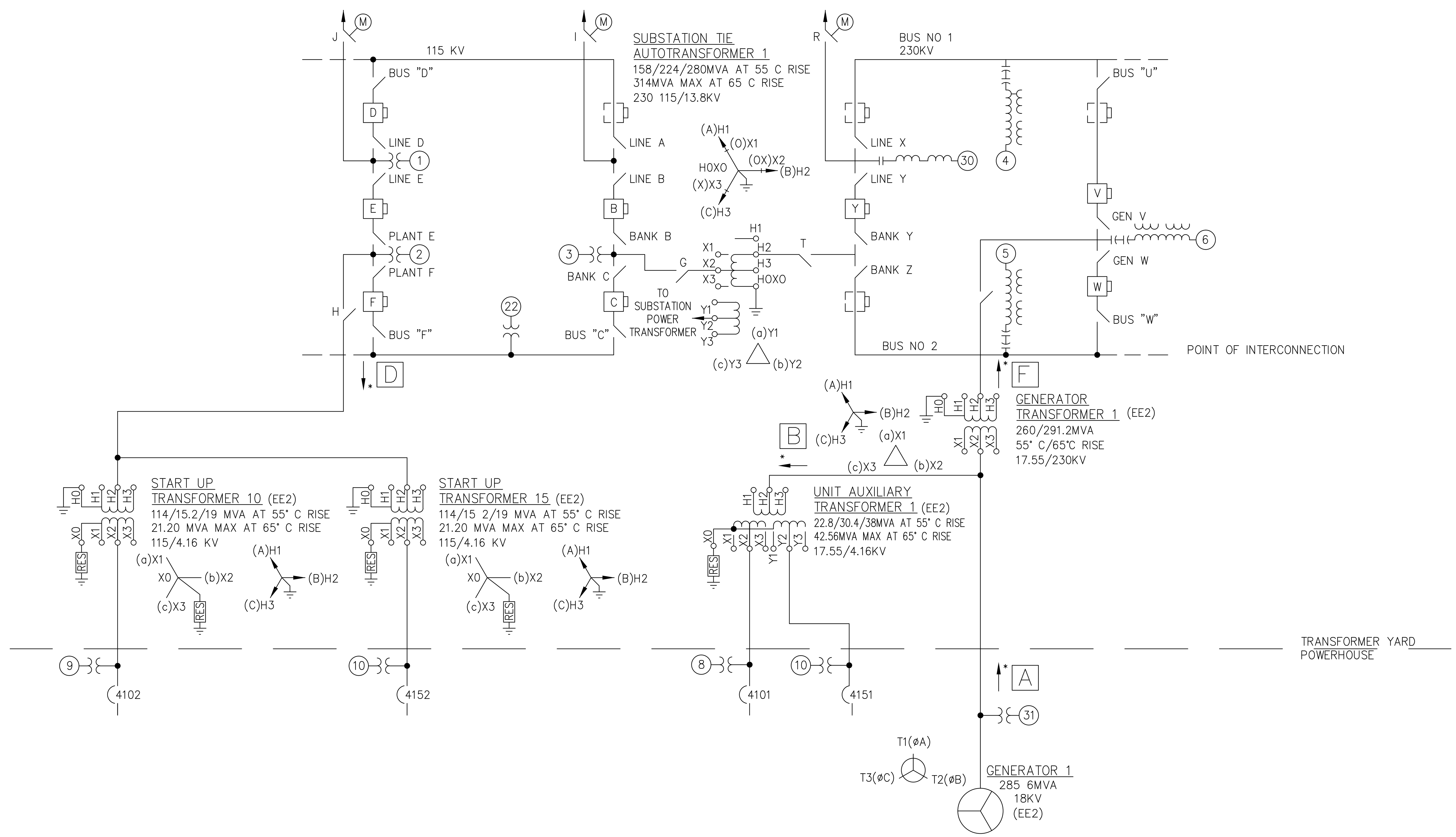
Auxiliary bus voltage was the limiting factor for the minimum stable load and maximum lagging power factor. At maximum stable load and maximum leading power factor the limiting factor was the generator terminal voltage. At maximum real output and maximum leading power factor the limiting factor was generator stator current and the under exciter limiter was reached. For the maximum real output and maximum lagging power factor the limiting factor was the auxiliary bus voltage.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

- Generator hydrogen pressure at time of test (if applicable) 42.0

Date that data shown in last verification column in table above was taken 05/24/2016

Appendix A



* – POSITIVE NUMBERS INDICATE POWER FLOW IN DIRECTION OF ARROW; NEGATIVE NUMBERS INDICATE POWER FLOW IN OPPOSITE DIRECTION OF ARROW.

NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	REFERENCE DWG'S

TRI-STATE
Generation and Transmission Association, Inc.

VENDOR NAME ·
VENDOR DWG. NUMBER ·
CONTRACT NUMBER ·
ORDER NUMBER ·

ESCALANTE GENERATING STATION
SIMPLIFIED ONE–LINE DIAGRAM
FOR NERC STANDARD MOD–025–2

DWN. BARBARA HERRERA	SCALE NTS	DWG. NO. 0023–064–02–0042	SHEET 1
CH'K'D'. DAVE READIO	DATE 08–06–15		REV. 0
APPR. ·			

MERIDIAN

(A) 08–06–15 (BJH)

All times = MST

Testing Data
Tri-State Generation and Transmission Association
Escalante Generating Station

Date: (MM/DD/YY) 5/24/16

Time at start of Test (HH:MM): 03:51

Air Temperature at start: 45.1 **(°F)** (BA10 or AMBIENT-Air)

Humidity at start: 41.16 **%** (REL-HUMIDITY)

Hydrogen Pressure: 42.0 **(psi)** (GG12)

Time at end of Test (HH:MM): ~~[illegible]~~

Air Temperature at end: ~~[illegible]~~ **(°F)** (BA10 or AMBIENT-Air)

Humidity at end: ~~[illegible]~~ **%** (REL-HUMIDITY)

At minimum stable load and maximum lagging power factor:

- Time when maximum lagging power factor is reached (HH:MM) 0400
- Gross MW EG220 100.1
- Gross MVAR EG222 42.4
- Net MW EG221 88.8
- Net MVAR EG219 34.44
- Auxiliary bus MW:
  - EAP-4100-MW 5.42
  - EAP-4150-MW 5.61
- Auxiliary bus MVAR:
  - EAP-4100-MVAR 3.745
  - EAP-4150-MVAR 3.951

- Generator field voltage EG_EXC_FLD_VOLTS 216.0
- Generator field current EG_EXC_FLD_AMP 806.5
- Generator field temperature EG-EXC-FLD 47.2
- Generator terminal voltage:
    - EG_GEN1_AB_VOLTS 18546.52
    - EG_GEN1_BC_VOLTS 18541.41
    - EG_GEN1_CA_VOLTS 18497.73
- 4160V Switchgear 4100 bus voltage EA4111 4352 6
- 4160V Switchgear 4150 bus voltage EA4161 4339.7
- 480V Load Center 5100 bus voltage EAP5100_VOLT 492.5
- Generator stator current:
    - EG_GEN1_PHA_AMP 3342.6
    - EG_GEN1_PHB_AMP 3347.5
    - EG_GEN1_PHC_AMP 3449.0
- Ambient air temperature. BA10 or AMBIENT-Air 44.4
- Ambient relative humidity. REL-HUMIDITY 41.25
- Generator hydrogen pressure. GG12 42.0
- Generator hydrogen temperature. GG450 33.76
- Generator hydrogen cooler water inlet temperature:
    - GG112 31.33
    - GG122 31.74
    - GG132 30.77
    - GG142 31.28

- Generator stator temperature for the 6 RTD's:
  - EG200A 39.9
  - EG200B 38.1
  - EG200C 37.6
  - EG210A 40.5
  - EG210B 39.1
  - EG210C 37.0
- Step-up transformer winding estimated hot-spot temperature (manually collected from transformer) 40°
- Unit auxiliary transformer winding estimated hot-spot temperature (manually collected from transformer) 30°
- 230-kV Substation voltage (from dispatch) 240.9
- 115-kV Substation voltage (from dispatch) 119.9

Describe the limiting factor in the test, i.e., was the field current limit reached, was the stator current limit reached, was a bus voltage limit reached?:

Limiting factor was 4100 bus voltage; highest voltage seen was 4355 volts; max is 4356.

At minimum stable load and maximum leading MVAR's:

- Time when maximum leading MVAR's is reached (HH:MM) 0420
- Gross MW EG220 102.4
- Gross MVAR EG222 -28.8
- Net MW EG221 91.5
- Net MVAR EG219 -34.95
- Auxiliary bus MW:
  - EAP-4100-MW 3.169
  - EAP-4150-MW 3.32~
- Auxiliary bus MVAR:
  - EAP-4100-MVAR 3.1450
  - EAP-4150-MVAR 3.3162
- Generator field voltage EG_EXC_FLD_VOLTS 151.6
- Generator field current EG_EXC_FLD_AMP 568.5
- Generator field temperature EG-EXC-FLD 41.0
- Generator terminal voltage:
  - EG_GEN1_AB_VOLTS 17336.44
  - EG_GEN1_BC_VOLTS 17343.26
  - EG_GEN1_CA_VOLTS 17282.46
- 4160V Switchgear 4100 bus voltage EA4111 4071.1
- 4160V Switchgear 4150 bus voltage EA4161 4061.9
- 480V Load Center 5100 bus voltage EAP5100_VOLT 461.2
- Generator stator current:

- EG_GEN1_PHA_AMP 3447.2
- EG_GEN1_PHB_AMP 3530.7
- EG_GEN1_PHC_AMP 3583.9

- Ambient air temperature. BA10 or AMBIENT-Air 45.5
- Ambient relative humidity. REL-HUMIDITY 44.15
- Generator hydrogen pressure. GG12 41.9
- Generator hydrogen temperature. GG450 33.56
- Generator hydrogen cooler water inlet temperature:
  - GG112 31.28
  - GG122 31.69
  - GG132 30.77
  - GG142 31.18
- Generator stator temperature for the 6 RTD's:
  - EG200A 39.2
  - EG200B 37.7
  - EG200C 37.1
  - EG210A 39.9
  - EG210B 38.7
  - EG210C 364
- Step-up transformer winding estimated hot-spot temperature (manually collected from transformer) 40°
- Unit auxiliary transformer winding estimated hot-spot temperature (manually collected from transformer) 30°

- 230-kV Substation voltage (from dispatch) 230.0
- 115-kV Substation voltage (from dispatch) 115.1

Describe the limiting factor in the test, i.e., was the field current limit reached, was the stator current limit reached, was a bus voltage limit reached?:

Generator terminal voltage limit was reached 17280 V ; tried to go lower; voltage fell below limit raised excite back up.

At maximum real output and maximum leading MVAR's:

- Time when maximum lagging power factor is reached (HH:MM) 1027
- Gross MW EG220 269.6
- Gross MVAR EG222 -10.62
- Net MW EG221 252.6
- Net MVAR EG219 -19.5
- Auxiliary bus MW:
  - EAP-4100-MW 8.09
  - EAP-4150-MW 8.93
- Auxiliary bus MVAR:
  - EAP-4100-MVAR 4.283
  - EAP-4150-MVAR 4.637
- Generator field voltage EG_EXC_FLD_VOLTS 294.9
- Generator field current EG_EXC_FLD_AMP 1066.0
- Generator field temperature EG-EXC-FLD 61.1
- Generator terminal voltage:
  - EG_GEN1_AB_VOLTS 17533.1
  - EG_GEN1_BC_VOLTS 17523.4
  - EG_GEN1_CA_VOLTS 17,458.5
- 4160V Switchgear 4100 bus voltage EA4111 4096.0
- 4160V Switchgear 4150 bus voltage EA4161 4078.0
- 480V Load Center 5100 bus voltage EAP5100_VOLT 463.8
- Generator stator current:

- EG_GEN1_PHA_AMP 8764.4
- EG_GEN1_PHB_AMP 8869.8
- EG_GEN1_PHC_AMP 8948.0

- Ambient air temperature. BA10 or AMBIENT-Air 66.94
- Ambient relative humidity. REL-HUMIDITY 15.28
- Generator hydrogen pressure. GG12 43.0
- Generator hydrogen temperature. GG450 38.96
- Generator hydrogen cooler water inlet temperature:
  - GG112 35.03
  - GG122 35.54
  - GG132 35.08
  - GG142 35.49
- Generator stator temperature for the 6 RTD's:
  - EG200A 55.0
  - EG200B 51.8
  - EG200C 51.9
  - EG210A 55.5
  - EG210B 53.6
  - EG210C 51.7
- Step-up transformer winding estimated hot-spot temperature (manually collected from transformer) 58°
- Unit auxiliary transformer winding estimated hot-spot temperature (manually collected from transformer) 37°

- 230-kV Substation voltage (from dispatch) 231.9
- 115-kV Substation voltage (from dispatch) 116.0

Describe the limiting factor in the test, i.e., was the field current limit reached, was the stator current limit reached, was a bus voltage limit reached?:

Stator current limit & UEL

		MAX LEADING MVAR LIMITS MIN	MAX LEADING MVAR LIMITS MAX
GROSS MW	269.6 MWG	265	272
GROSS MVAR	-10.62 MVAR	0	-90
GEN FIELD CURRENT	1066.0 AMPS	850	–
GEN FIELD VOLTAGE	294.9 VOLTS	–	500
GEN FIELD TEMPERATURE	61.1 DEG C	–	110
GEN TERMINAL VOLTAGE A-B	17533.1 VOLTS	17271	18711
GEN TERMINAL VOLTAGE B-C	17523.4 VOLTS	17271	18711
GEN TERMINAL VOLTAGE C-A	17458.5 VOLTS	17271	18711
GEN STATOR CURRENT PH-A	8764.4 AMPS	–	8932
GEN STATOR CURRENT PH-B	8869.8 AMPS	–	8932
GEN STATOR CURRENT PH-C	8948.0 AMPS	–	8932
GEN HYDROGEN PRESS	43.0 PSIG	39	41
GEN HYDROGEN TEMP	38.96 DEG C		40
4100 BUS VOLTS	4096.0 VOLTS	3838	4356
4150 BUS VOLTS	4078.0 VOLTS	3838	4356
LC5100 BUS VOLTS	463.8 VOLTS	441	501
230KV SUBSTATION VOLTS	CALL DISPATCH	218.5	253

MIN AND MAX LIMITS FOR ALL TESTS

MAXIMUM MEGAWATT

MAX LAGGING MVAR LIMITS MIN	MAX LAGGING MVAR LIMITS MAX
265	272
0	140
–	1333

MAX LEADING MVAR LIMITS MIN	MAX LEADING MVAR LIMITS MAX
98	102
-80	-125
350	–

MINIMUM MEGAWATT

MAX LAGGING MVAR LIMITS MIN	MAX LAGGING MVAR LIMITS MAX
98	102
170	240
1320	1333

COUPLING END STATOR TEMP	MAX LIMIT
PHASE A 55.0 DEG C	100 C
PHASE B 51.8 DEG C	100 C
PHASE C 51.9 DEG C	100 C

COLLECTOR END STATOR TEMP	MAX LIMIT
PHASE A 55.5 DEG C	100 C
PHASE B 53.6 DEG C	100 C
PHASE C 51.7 DEG C	100 C

NET MW	252.6 MWN
NET MVAR	-19.5 MVAR
4100 BUS MW	8.03 MW
4150 BUS MW	8.93 MW
4100 BUS MVAR	4.283 MVAR
4150 BUS MVAR	4.637 MVAR
GEN HYD COOLER 1 IN TEMP	35.03 DEG C
GEN HYD COOLER 2 IN TEMP	35.54 DEG C
GEN HYD COOLER 3 IN TEMP	35.08 DEG C
GEN HYD COOLER 4 IN TEMP	35.49 DEG C
GEN HYD COOLER 1 OUT TEMP	41.27 DEG C
GEN HYD COOLER 2 OUT TEMP	41.17 DEG C
GEN HYD COOLER 3 OUT TEMP	42.34 DEG C
GEN HYD COOLER 4 OUT TEMP	42.54 DEG C
AMBIENT AIR TEMP	66.94 DEG F
AMBIENT RELATIVE HUMIDITY	15.28 PCT

		MAX LEADING MVAR LIMITS MIN	MAX LEADING MVAR LIMITS MAX	MAXIMUM MEGAWATT	MAX LAGGING MVAR LIMITS MIN	MAX LAGGING MVAR LIMITS MAX	MAX LEADING MVAR LIMITS MIN	MAX LEADING MVAR LIMITS MAX	MINIMUM MEGAWATT	MAX LAGGING MVAR LIMITS MIN	MAX LAGGING MVAR LIMITS MAX
GROSS MW	268.1 MWG	265	272		265	272	98	102		98	102
GROSS MVAR	57.55 MVAR	0	-90		0	140	-80	-125		170	240
GEN FIELD CURRENT	1214.4 AMPS	850	–		–	1333	350	–		1320	1333
GEN FIELD VOLTAGE	344.4 VOLTS	–	500								
GEN FIELD TEMPERATURE	66.5 DEG C	–	110								
GEN TERMINAL VOLTAGE A-B	18674.8 VOLTS	17271	18711								
GEN TERMINAL VOLTAGE B-C	18657.3 VOLTS	17271	18711								
GEN TERMINAL VOLTAGE C-A	18605.4 VOLTS	17271	18711								
GEN STATOR CURRENT PH-A	8450.4 AMPS	–	8932								
GEN STATOR CURRENT PH-B	8527.8 AMPS	–	8932								
GEN STATOR CURRENT PH-C	8617.2 AMPS	–	8932								
GEN HYDROGEN PRESS	42.9 PSIG	39	41								
GEN HYDROGEN TEMP	39.37 DEG C		40								
4100 BUS VOLTS	4358.8 VOLTS	3838	4356								
4150 BUS VOLTS	4343.2 VOLTS	3838	4356								
LC5100 BUS VOLTS	492.7 VOLTS	441	501								
230KV SUBSTATION VOLTS	CALL DISPATCH	218.5	253								

MIN AND MAX LIMITS FOR ALL TEST'S

NET MW	251.2 MWN
NET MVAR	50.0 MVAR
4100 BUS MW	8.17 MW
4150 BUS MW	8.74 MW
4100 BUS MVAR	4.937 MVAR
4150 BUS MVAR	5.238 MVAR
GEN HYD COOLER 1 IN TEMP	35.44 DEG C
GEN HYD COOLER 2 IN TEMP	35.89 DEG C
GEN HYD COOLER 3 IN TEMP	35.44 DEG C
GEN HYD COOLER 4 IN TEMP	35.84 DEG C
GEN HYD COOLER 1 OUT TEMP	41.78 DEG C
GEN HYD COOLER 2 OUT TEMP	41.68 DEG C
GEN HYD COOLER 3 OUT TEMP	42.89 DEG C
GEN HYD COOLER 4 OUT TEMP	43.10 DEG C
AMBIENT AIR TEMP	72.50 DEG F
AMBIENT RELATIVE HUMIDITY	10.89 PCT

COUPLING END STATOR TEMP	MAX LIMIT
PHASE A 55.1 DEG C	100 C
PHASE B 52.0 DEG C	100 C
PHASE C 52.1 DEG C	100 C

COLLECTOR END STATOR TEMP	MAX LIMIT
PHASE A 55.8 DEG C	100 C
PHASE B 53.7 DEG C	100 C
PHASE C 51.9 DEG C	100 C

		MAX LEADING MVAR LIMITS MIN	MAX LEADING MVAR LIMITS MAX	MAX LAGGING MVAR LIMITS MIN	MAX LAGGING MVAR LIMITS MAX	MAX LEADING MVAR LIMITS MIN	MAX LEADING MVAR LIMITS MAX	MAX LAGGING MVAR LIMITS MIN	MAX LAGGING MVAR LIMITS MAX
		MAXIMUM MEGAWATT				MINIMUM MEGAWATT			
GROSS MW	267.5 MWG	265	272	265	272	98	102	98	102
GROSS MVAR	68.06 MVAR	[redacted]	-90	0	140	-80	-125	170	240
GEN FIELD CURRENT	1215.3 AMPS	850	–	–	1333	350	–	1320	1333

		MIN	MAX
GEN FIELD VOLTAGE	348.0 VOLTS	–	500
GEN FIELD TEMPERATURE	69.3 DEG C	–	110
GEN TERMINAL VOLTAGE A-B	18675.3 VOLTS	17271	18711
GEN TERMINAL VOLTAGE B-C	18655.2 VOLTS	17271	18711
GEN TERMINAL VOLTAGE C-A	18603.7 VOLTS	17271	18711
GEN STATOR CURRENT PH-A	8424.8 AMPS	–	8932
GEN STATOR CURRENT PH-B	8503.3 AMPS	–	8932
GEN STATOR CURRENT PH-C	8592.0 AMPS	–	8932
GEN HYDROGEN PRESS	43.1 PSIG	39	41
GEN HYDROGEN TEMP	41.06 DEG C		40
4100 BUS VOLTS	4359.0 VOLTS	3838	4356
4150 BUS VOLTS	4340.5 VOLTS	3838	4356
LC5100 BUS VOLTS	492.9 VOLTS	441	501
230KV SUBSTATION VOLTS	CALL DISPATCH	218.5	253

MIN AND MAX LIMITS FOR ALL TESTS

COUPLING END STATOR TEMP	MAX LIMIT
PHASE A 58.3 DEG C	100 C
PHASE B 54.7 DEG C	100 C
PHASE C 54.7 DEG C	100 C

COLLECTOR END STATOR TEMP	MAX LIMIT
PHASE A 58.9 DEG C	100 C
PHASE B 56.4 DEG C	100 C
PHASE C 54.8 DEG C	100 C

NET MW	250.2 MWN
NET MVAR	50.0 MVAR
4100 BUS MW	8.32 MW
4150 BUS MW	8.90 MW
4100 BUS MVAR	4.973 MVAR
4150 BUS MVAR	5.313 MVAR
GEN HYD COOLER 1 IN TEMP	36.81 DEG C
GEN HYD COOLER 2 IN TEMP	37.37 DEG C
GEN HYD COOLER 3 IN TEMP	36.91 DEG C
GEN HYD COOLER 4 IN TEMP	37.36 DEG C
GEN HYD COOLER 1 OUT TEMP	43.65 DEG C
GEN HYD COOLER 2 OUT TEMP	43.45 DEG C
GEN HYD COOLER 3 OUT TEMP	44.97 DEG C
GEN HYD COOLER 4 OUT TEMP	45.02 DEG C
AMBIENT AIR TEMP	71.40 DEG F
AMBIENT RELATIVE HUMIDITY	11.38 PCT

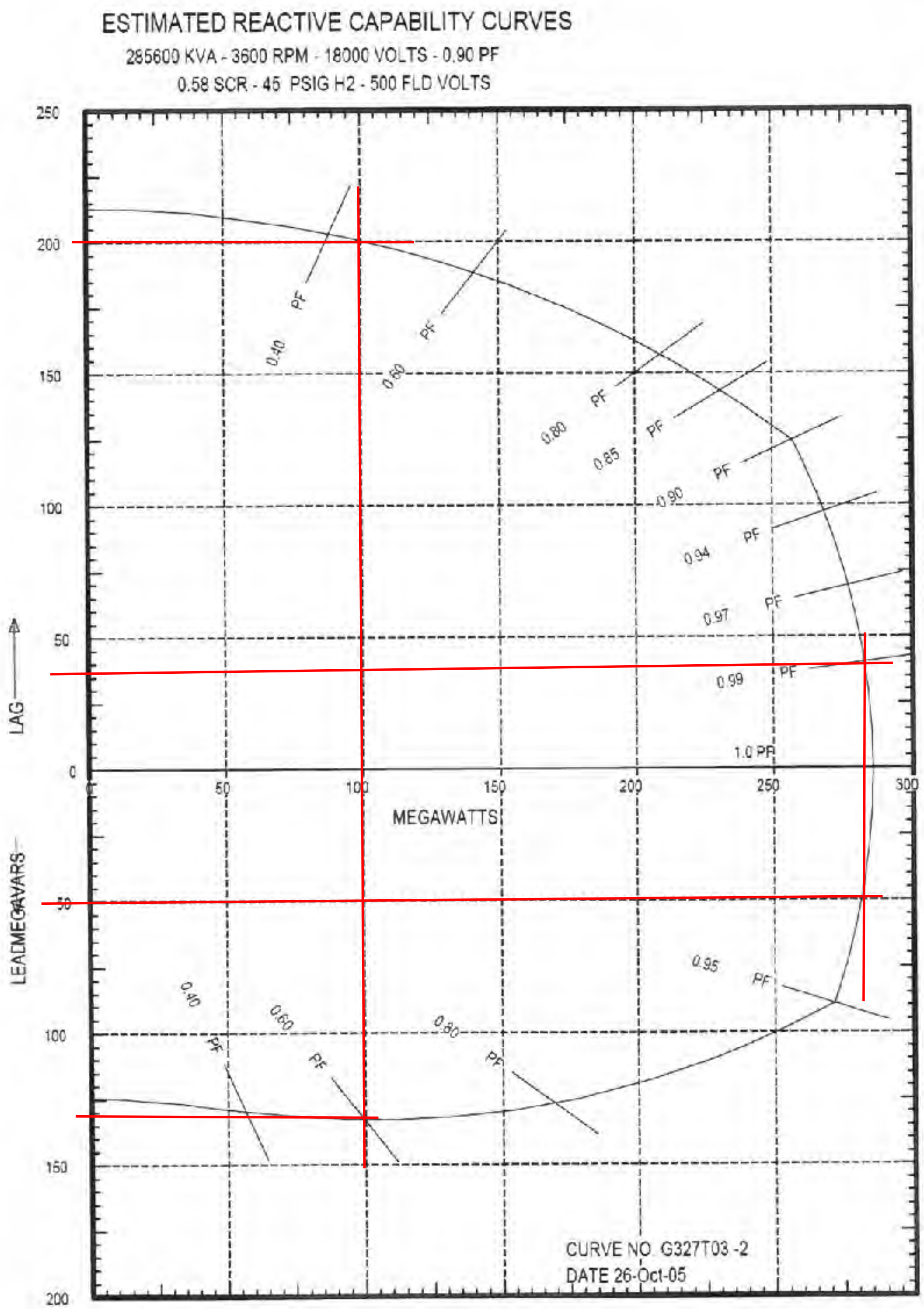


Figure 4.2: Generator Reactive Capability Curve for Escalante Unit

Exhibit No. TS-023

Laramie River Unit 2

MOD-025 Test Reports and Capability Curves

Kestrel
Power Engineering

Model Validation and Coordination Study

Laramie River Station Unit 2

K2016_037_R2

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Kestrel Power Engineering

Rev.	Date	Submitted by	Comments
0	April 25, 2016	Jerry Thompson, E.I.T.	
1	May 18, 2016	Jerry Thompson, E.I.T.	Update to L90 50 element
2	July 7, 2016	Jerry Thompson, E.I.T.	MOD-027 update, correction to wording Section 6.4

Kestrel
Power Engineering

Model Validation and Coordination Study

Laramie River Station Unit 2

K2016_037_R2

Prepared by: Jerry Thompson, E.I.T.

Peer Review by: Mike Fogarty, P.E.

EXECUTIVE SUMMARY

This report provides details of the tests and engineering assessment performed on the generator, exciter, governor, power system stabilizer, and protective relaying at Laramie River Station Unit 2 on April 15, 2016.

Models have been provided, suitable for meeting compliance requirements. The following are the main conclusions/recommendations from this report:

1. Reactive capability testing was performed on the unit. Calculated reactive capability and relay and limiter coordination curves and the NERC MOD-025 reactive capability forms are provided as part of this report.
2. The excitation system and power system stabilizer models, figures, and documentation provided in this document address NERC Std. MOD-026-1 requirements.
3. The turbine-governor models, figures, and documentation provided in this document address NERC Std. MOD-027-1 requirements. This unit is not responsive to both over and under frequency excursion events; the unit does not operate in a frequency control mode, except for during normal start-up and shut down. MOD-027-1 R2 is satisfied per Attachment 1, Row 7 [6].
4. The excitation system continues to function correctly as commissioned.
5. The power system stabilizer is set to meet regulatory requirements and is in service above 138 MW (0.2 pu).
6. The steam turbine governor does not respond to system frequency deviations. As such, it should be represented by a fixed mechanical power source.
7. No changes are required to meet NERC Standard PRC-019, PRC-024, and PRC-025 requirements.

The exciter, stabilizer, governor, and relay settings documented in this report must not be changed without a thorough review and notification of the Transmission Planner.

The Appendices to this report contain details and reference material:

Appendix A: Models/Rating Nameplates
Appendix B: Characteristic Curves
Appendix C: Measurements
Appendix D: Protection Coordination Plots
Appendix E: Reactive Capability Forms
Appendix F: Settings
Appendix G: Glossary

Table of Contents

1 GENERATOR PARAMETERS

Quantities in this report are expressed in per unit or engineering units (e.g. kV, MVA). Values expressed in per-unit are divided by a base value such that they will normally range between 0 and 1 for normal operating conditions. The per unit base data summarized in Table A2 correspond to the values used in reporting the generator impedances and time constants.

A list of generator parameters was supplied in reference [11], and these were used as the starting point for modeling this generator. Appendix A3 summarizes the recommended simulation model and parameters. Confirmation of key generator parameters was made by test as listed below.

1.1 Open Circuit Saturation Curve

Figure B1 displays the open-circuit saturation curve, along with the tangent to the lower measurements, forming the air-gap line. The base field current is determined as the intersection of the air-gap line and rated terminal voltage (i.e. 1 pu). The field resistance corresponding to a temperature of 100°C was used to determine the base field voltage listed in Table A2.

The saturation coefficients S(1.0) and S(1.2) in Table A3 describe the saturation curve of Figure B1 using the quadratic saturation curve of the GENROU model.

1.2 Time Constants and Transient Reactances

The d- and q-axis parameters were confirmed by a simulation of the on line step response, such as the one shown in Figure C1. The simulations include the effects of temperature on the rotor resistance and field voltage.

1.3 Combined Turbo-Generator Inertia

A partial load rejection test was performed during previous testing [11] confirm the value of inertia (H). The value has been used without change.

1.4 Synchronous Reactances

Generator synchronous reactances were confirmed from static measurements of field current, terminal voltage, active and reactive power. The field current calculated using the recommended synchronous reactance values and generator saturation parameters are compared with the measured values in Table C4.

1.5 Generator Capability Curve

Calculated capability curves are shown in Figures B3 and B4. The curves have been provided for the purpose of satisfying a portion of NERC PRC-019 requirement to show the coordination of the excitation limiters with protective relays and unit ratings; they are not intended to supersede the utility's official curves. The capability curves have been calculated based on the measured results and verified generator impedance and saturation data. The limit for lagging power factor conditions is a function of the nameplate field current rating listed in Table A2. It must be remembered that this limit is highly dependent on terminal voltage, and therefore field current, not reactive power, should be monitored during extended over-excited operation.

The limits shown in the leading power factor region are the exciter under excitation limiter (UEL) curve, generator core-end heating limit and loss of excitation (LOE) relay characteristics. Excitation limiters and relay coordination are discussed elsewhere in the report.

In the leading power factor region, no attempt was made to identify the steady state stability boundary. The conventional assumptions used to calculate the steady state stability limit, as shown in the coordination example NERC Std. PRC-019-2 [7], are based on operation with fixed field voltage. This does not apply to this unit, as it is equipped with a continuously-acting automatic voltage regulator and power system stabilizer.

Additional information regarding the coordination between excitation limiters, generator protection, and equipment capability is provided in Section 5.

2 EXCITATION SYSTEM

This unit is equipped with a GE EX2100 full static excitation system fed from the generator terminals.

2.1 Power Stage

The power stage consists of 6-pulse thyristor bridges supplied by an excitation transformer with ratings summarized in Table A2.

The theoretical no-load ceiling voltage is calculated from the transformer secondary voltage:

$$\begin{aligned} \mathrm{E_{d0}} &= 1.35 * \mathrm{V_{SEC}} \\ &= 1.35 * 1090\ \mathrm{Vac} \\ &= 1472\ \mathrm{Vdc}\ = 7.80\ \mathrm{pu} \end{aligned}$$

The no-load ceiling voltages are established by the bridge advance and retard firing limits:

$$\begin{aligned} V_{RMAX} &= E_{d0} * \cos(\alpha_{min}) = 1.00 * E_{d0} \\ &= 1472\ \mathrm{Vdc} = 7.80\ \mathrm{pu} \end{aligned}$$

$$\begin{aligned} V_{RMIN} &= E_{d0} * \cos(\alpha_{max}) = -0.80 * E_{d0} \\ &= \text{-}1177\ \mathrm{Vdc} = \text{-}6.24\ \mathrm{pu} \end{aligned}$$

These ceiling voltages are entered as a fraction of the no-load ceiling E_{do} in the ST4B model (Appendix A4).

The effect of exciter transformer impedance on exciter output voltage is represented by the commutating impedance, K_C.

2.2 Automatic Voltage Regulator

Control is provided by a GE EX2100 digital voltage regulator which also implements the limiter and power system stabilizer functions. The EX2100 digital control implements a proportional-integral (PI) transfer function based on terminal voltage feedback. The appropriate simulation model is the IEEE type ST4B [1] shown in Appendix A4.

The AVR proportional and integral gains, K_{PR} and K_{RI} respectively, are set via the EX2100 software.

The terminal voltage measurement time constant, T_r, and the exciter time constant, T_a, are approximations of the device delays and filters. The model values selected provide a good representation of the closed-loop voltage regulator response using the available simulation model. The model values used in the simulation program are limited by the program used and the simulation time step of the study as noted in Appendix A4.

The measured closed-loop AVR step-response, with the unit operating online is shown in Figure C1. The simulated response with the AVR gains and time constant parameters listed in Appendix A4 closely matches the measured result.

2.3 Reactive Current Compensation

This unit is connected to the bulk power system through a dedicated step-up transformer. In this case, reactive current compensation (RCC) is typically not used, and the parameter has been set to 0.

2.4 Under Excitation Limiter

The UEL was set by the manufacturer to operate at levels tabulated in Appendix F and shown with the capability curves (Figures B3 and B4). The settings match the core end heating curve and an offset is then used to provide a margin between the UEL and core end heating curve.

The UEL was not tested dynamically.

2.5 Over Flux Limiter

The unit is equipped with a V/Hz limiter function within the exciter control. The as-commissioned V/Hz limit setting is 109% Et/% frequency. Coordination with V/Hz relays is discussed in Section 5.

2.6 Pf/Var Controls

This unit is equipped with both power factor (pf) and reactive power set point (VAR) controllers. NERC VAR-002 prohibits the use of pf/Var set point controllers on units connected to the bulk power system, so they were left turned off.

2.7 Over Excitation Limiter

The OEL implements both an inverse-time and fixed-time characteristic. The manufacturer's inverse OEL settings are 102% trip pick-up and an alarm pickup of 70% of the trip level, 112% rated field current for 120 seconds. The fixed-time OEL triggers at 140% rated field current after 1 second(s), and limits field current to 125% of rated until the inverse time OEL triggers. The OEL then limits to 100% of rated field current with compensation for temperature. The OEL settings are shown in Appendix F.

The OEL was not tested dynamically.

3 POWER SYSTEM STABILIZER

The GE EX2100 digital excitation system includes a power system stabilizer that provides supplementary damping. The stabilizer implements an IEEE standard type PSS2A transfer function [1] shown in Appendix A5. The stabilizer settings are tabulated in Appendix F.

It should be noted that the EX2100 software is configured as the PSS2B option. The software does not employ the third lead/lag stage of the PSS2B structure, but does make use of the optional biquadratic filters. The biquadratic filters are typically used to reduce the interaction of the PSS with torsional modes of the turbine. As such, the software implementation can be represented as a PSS2A structure.

3.1 Stabilizer Inputs

This stabilizer uses two measured inputs, electrical power and compensated frequency, and is the presently accepted industry standard throughout North America. Both inputs are derived from the generator PT and CT secondary signals. The first input is the compensated frequency calculated based on the parameter $X_{q\ COMP}$ shown in Table A5. The available simulation models do not have the option to use compensated frequency as an input to the PSS model, so speed deviation is used instead.

The compensation setting, *Xq for slip calc*, is selected to produce an internal generator voltage phasor that is tied to rotor oscillations. The value of *Xq for slip calc* is selected based on comparison between simulation and measurement of the stabilizer's damping with final PSS gain.

3.2 Stabilizer Tuning

The PSS settings were selected by the manufacturer. The calculated terminal voltage versus AVR reference frequency response (inverted) along with the manufacturer-selected PSS phase compensation is shown in Figure B5. The difference between the selection and requirement is within the accepted ±30° bound [12] required by WECC [13] over the range 0.1 Hz to 1.0 Hz.

Improvements to inter-area mode damping (frequencies below 0.7 Hz) cannot be assessed through local tests. Simulations representing a large portion of the interconnected power system are required to assess the effectiveness of a given PSS implementation on these modes. No changes to the selected parameters are recommended without detailed study.

The selected parameters provide damping of the unit's local mode of oscillation (1.7 Hz), as shown in Figure C2 with the PSS on at its as-left gain and Figure C1 with the PSS off. The result at twice the as-left stabilizer gain is plotted in Figure C3. The final gain provides more than 6dB gain margin. Higher PSS gains result in higher frequency modes in field voltage and stabilizer output and variations in terminal voltage and reactive power during mechanical power changes.

3.3 Output Limits and Control

The PSS output limits were set to +/- 10% terminal voltage reference.

The PSS is selected to automatically turn on above the minimum load (0.2 pu), and turn off at a slightly lower level (0.15 pu) to provide some hysteresis. This hysteresis is required to prevent multiple on/off operations during turbine output changes near the turn-on level.

This stabilizer design includes a "ramp tracking" filter to minimize terminal voltage and reactive power changes during normal loading and unloading.

4 TURBINE GOVERNOR

The coal-fired steam turbine for this unit is connected directly to the generator rotor, which operates at 3600 rpm. The governor employed is an Emerson Ovation digital controller.

The unit is not responsive to both over and under frequency excursion events; the unit operates on valve position control and does not receive influence from system frequency deviations. This has been confirmed from ambient measurements of frequency and active power at full and partial load, as presented in Figures C5 and C6.

As such, the unit should be modeled as having a fixed mechanical power source for typical dynamic simulation studies. The representation of a constant mechanical power from the turbine is usually automatically assumed when no explicit turbine/speed governor model is provided. Thus, the fact that no explicit model has been provided implies that these units will be represented as fixed mechanical power sources and, as such, the requirements from NERC Std. MOD-027 are met.

5 LIMITER AND PROTECTION COORDINATION

5.1 Introduction

NERC standards PRC-019-2 [7] and PRC-024-2 [8] have been instated to ensure coordination of generating units' protective relay settings with voltage regulator controls, limit functions, equipment capabilities, and NERC voltage/frequency ride-through requirements. Review of relevant protective relay settings has been performed to confirm proper coordination in accordance with NERC standards, and with reference to the IEEE Guide for AC Generator Protection [3].

Laramie River Station Unit 2 is equipped with hardware as shown in Table A1. The following sub-sections summarize the relevant settings and their relation to the NERC standards and industry standard practice. Base values (voltage, current and impedance) are listed in Table A2.

5.2 PRC-019 Coordination Requirements

NERC Standard PRC-019-2 [7] requires the following (Kestrel's highlights):

> R1.1.1 - The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnection the generator unnecessarily.
>
> R1.1.2 - The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to **limit the extent of damage** when operating conditions exceed equipment capabilities or stability limits.

Thus, it is conceivable that some protection elements are set beyond the equipment capability and, thus, the unit would operate for a certain period of time beyond its capability or stability limit. As long as the risk of damage is considered acceptable by the equipment owner, the requirement from PRC-019-2 is met.

5.3 PRC-019 and Coordination with Steady State Stability Limit

The steady state stability limit in the leading power factor region was not included in the coordination assessment. The conventional assumptions used to calculate the steady state stability limit, as shown in the coordination example NERC Std. PRC-019-2 [7], are based on operation with fixed field voltage. This does not apply to this unit, as it is equipped with a continuously-acting automatic voltage regulator.

Per NERC Std. VAR-002-4 [10], the unit should be operated in the automatic voltage control mode (AVR in service and controlling voltage) in most cases (excluding start-up, shutdown or testing). Operation in any other mode, including manual control, would require a justification as part of the notification process to the Transmission Operator.

Operation in AVR mode significantly affects the steady state stability limit [15], moving the stability limit much beyond the capability of the generator and usually beyond the curves associated with the loss-of-excitation relays.

On the other hand, the under-excitation limiter (UEL) and other elements of the excitation control are an integral part of the operation on automatic voltage control. The UEL curve shown in Figures B3 and B4 is specific to the operation on automatic voltage control. Thus, including the steady state stability limit associated with operation in manual control and the UEL characteristic on the same coordination figure would be inconsistent.

Operation on manual control implies operation in a less stable mode than on automatic voltage control. It typically also implies that the excitation system will not provide the limiting function (UEL), so the loss of excitation relay or the steady state stability limit might be reached during under-excited operation on manual control. In either case, it will result in the trip of the generation unit. As long as the protection settings are limiting the risk of damage to the equipment, PRC-019 does not require the protection settings to prevent operation beyond the stability limit (R1.1.2).

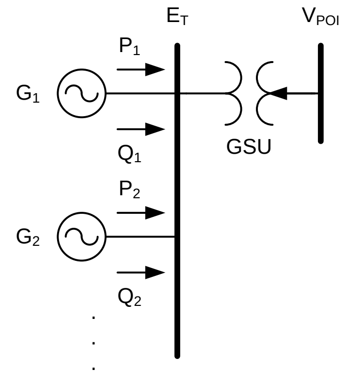
5.4 PRC-024 Voltage Requirements

The Voltage Ride-Through Time Duration Curve in Attachment 2 of PRC-024-2 [8] specifically provides voltages at the point of interconnection (POI) to the Bulk Electric System (BES), which is the high-voltage side (HV) of the generator step-up transformer (GSU) for conventional generation units. On the other hand, the protective relays on conventional generation units are typically connected to PTs and CTs at the terminals of the machine, the low-voltage (LV) bus where the GSU is connected. Thus, the voltage ride-through time duration curves have been translated to the generator terminals to simplify the comparison of generator and GSU protection settings to the PRC-024 requirements. The generator terminal voltage is calculated considering the voltage at the POI given in voltage ride-through curves provided in PRC-024 and also considering the following loading conditions, believed to be the most probable for the generator unit, in accordance with Attachment 2 of PRC-024, particularly the section regarding evaluation of protective relay settings:

a) All units connected to the same transformer are online and operating.
b) All the units are dispatched at maximum power output, per the available information for these units. The maximum power output of each unit will be determined by their respective maximum turbine rated output or the maximum continuous rating (MCR) or will be calculated from the generator MVA and rated power factor.
c) For under-voltage conditions at the POI, all units will be dispatched at their rated power factor, corresponding to a maximum reactive power output. For over-voltage conditions at the POI, all units will be dispatched at 0.95 power factor (under-excited condition), resulting in reactive power absorption.

d) The excitation system is in AVR control mode considering a voltage reference setpoint within the usual operating range of the unit(s), in accordance with NERC Std. VAR-002 [10].

Based on these assumptions, the voltage-ride through time duration curve in PRC-024-2 will be reflected to the terminal bus of the generator(s) (LV bus of the GSU transformer). For each GSU in the plant, the calculations will be based on the following simplified one-line diagram:



Since these synchronous generators are operated on AVR control, the generator terminal voltage E_T is held constant or follows the reactive current compensation (RCC) setting (if applicable) independently of the voltage at the POI, until the reactive capability is reached, as shown in the figure below. Therefore, the generator terminal voltage will only deviate significantly from the AVR voltage reference setpoint once the reactive capability of the generation units is reached. In the assumptions above, the reactive capability of the unit is represented in a simplified manner, considering the rated power factor of the unit for over-excited operation (Q_{MAX}) and 0.95 power factor for under-excited operation (Q_{MIN}). It should be noted that these assumptions are similar to the current practice for representation of synchronous generators in power flow studies and other similar steady state calculations.

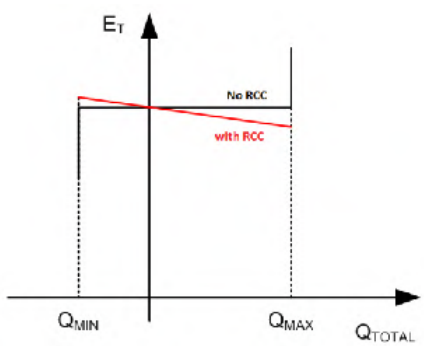


Figure D1 presents the calculated voltage ride-through time duration curve as seen from the generator terminal bus (LV bus of the GSU). The calculation of the voltage at the generator terminal bus is based on the assumptions listed above, the POI voltages given in PRC-024-2, and the GSU data shown in Appendix A2.

5.5 Under-Voltage Elements (27)

Generators built per the ANSI/IEEE C50.13 standard [2] for round rotor synchronous generators are designed for continuous online operation down to 95% of rated voltage. This includes continuous operation within the manufacturer provided generator capability curves (shown in Figures B3 and B4) down to 95% rated voltage. As such, some machines include under voltage limiter and/or protective devices.

The IEEE Guide [3] prescribes the under-voltage elements as an interlock for other protective devices, rarely to be applied as a standalone trip function.

The excitation system is not equipped with under-voltage limiter or protective functions.

The generator protection relay's under-voltage elements are set to alarm only. The implementation matches the IEEE recommendation. Under-voltage relay settings are shown in Appendix F2.

The protective relays' under-voltage settings meet NERC PRC-019 and PRC-024 requirements, as shown in Figure D1. No changes are required.

5.6 Over-Voltage Elements (59)

As with under-voltage, generators built per the ANSI/IEEE C50.13 standard [2] are designed for continuous online operation within the manufacturer provided generator capability curves up to 105% of rated voltage. As such, some machines include over voltage limiter and/or protective devices.

The IEEE Guide [3] recommends two stages of tripping for over-voltage conditions, generally as applied to hydro generators. The first stage is normally an instantaneous unit set to pick up at 130% to 150% of the nominal generator voltage. The second stage is an inverse-time element with pickup of approximately 110% nominal voltage. As described in the IEEE Guide [3], the over-voltage function may be configured to alarm only for steam and gas turbine generators, due to the rapid response of the speed-control systems and voltage regulators.

The excitation system is equipped with a definite time overvoltage element.

The generator protection relay's over-voltage elements are set to trip with definite time settings. Over-voltage relay settings are shown in Appendix F.

The protective relays' over-voltage settings meet NERC PRC-019 and PRC-024 requirements, as shown in Figure D1. No changes are required.

5.7 Volts/Hertz Elements (24)

The IEEE Guide [3] suggests either a single relay or double relay scheme for V/Hz protection. Recommended settings for a single, definite time relay are a pickup of 110% and delay of 6 seconds. The two-relay scheme includes a quick trip relay with pick up between 118% and 120% V/Hz and timer to trip set between 2 and 6 seconds. The second relay is set at 110% V/Hz and is to trip just below the manufacturer's recommended generator and/or transformer operating time at 110% V/Hz; the delay is typically between 45 and 60 seconds. Alternatively, a single inverse time relay can be used to closely match the generator or transformer V/Hz characteristic, whichever is more restrictive.

The excitation system includes a V/Hz limiter function as documented in Section 2.5 with a definite time characteristic. The excitation system also includes V/Hz protection with a composite characteristic.

The generator protection relay's V/Hz elements are set to trip with definite time characteristics. The implementation matches the IEEE recommendation. V/Hz relay settings are shown in Appendix F.

Generator and generator step-up transformer manufacturers' over-fluxing capability curves are not available; thus, the coordination of the equipment capabilities cannot be assessed against limiter and protection settings. Industry standards do not at present specify definite short time capabilities for

generators and transformers and the equipment manufacturers should provide overexcitation capability limits [3]. In the absence of actual OEM V/Hz capability information, the IEEE Guide [3] typical tripping recommendation of 118% setpoint with a delay between 2 and 6 seconds has been assumed as adequate to limit the extent of damage due to excessive overexcitation in this coordination study. If the manufacturer curves become available, the coordination study should be updated accordingly.

Coordination of the V/Hz elements is shown in Figure D2. Coordination of the V/Hz elements, under- and over-voltage elements, and NERC PRC-024 requirements are shown in Figure D1. The V/Hz elements are properly coordinated and no changes are required to meet PRC-019 requirements.

5.8 Loss of Excitation Elements (40)

The IEEE Guide [3] approach to loss of excitation protection employs two offset mho elements with both offset from the impedance plane by one-half the generator transient reactance $-X'_d/2$. The delayed element is set with a diameter equal to the d-axis synchronous reactance, X_d, with a delay between 0.5 and 0.6 seconds. The IEEE Guide [3] recommends that a transient stability study be performed to determine the appropriate unit specific time delay for this element. The instantaneous element is set with a diameter of 1 pu. Base impedance is listed in Table A2.

The excitation system is equipped with limiting and protective functions in the leading power factor region. The UEL operates as described in Section 2.4. The protective functions are in the form of LOE elements, matching the IEEE approach.

The relay loss of field elements match the IEEE recommended approach. Settings are shown in Appendix F.

Coordination of the loss of field elements with the unit's core end heating curve, under-excitation limiter (UEL), and 0.95 power factor are shown in Figures B3 and B4. No changes are required to meet PRC-019 requirements.

5.9 Frequency Elements (81)

The IEEE Guide [3] recommends coordination of frequency elements with the turbine manufacturer's permissible frequency-band operating time guidelines. The NERC PRC-024 standard has regional specific frequency ride-through requirements.

The excitation system has no frequency specific protective devices.

The generator protection relay's relay frequency settings are set with definite time characteristics. Settings are shown in Appendix F.

The protective devices cannot be assessed against equipment capability, as the manufacturer's permissible frequency duration curves for the turbine are not available. If the curves become available, the coordination study should be updated accordingly.

Coordination of the relay frequency elements with NERC PRC-024 requirements is shown in Figure D3. The relay settings satisfy the NERC Western region abnormal frequency ride-through requirements. No changes are required.

5.10 Field Thermal Protection

The IEEE Guide [3] recommends an inverse time relaying scheme in accordance with ANSI standards for short-time thermal capabilities for cylindrical rotor machines [2], with 5% to 10% margin between the relay characteristic and the field capability curve.

The excitation system provides both limiting and protective functions for field thermal protection, as documented in Section 2.7.

No discrete device is employed for field thermal protection.

Coordination of the excitations system's limiting and protective functions, and the ANSI curve for short time thermal capability is shown in Figure D4. Coordination of the excitation system functions in steady state, rated field current, and rated power factor are shown in the capability curves of Figures B3 and B4. No changes are required.

5.11 Stator Thermal Protection

The IEEE Guide [3] recommends an inverse time relaying scheme in accordance with ANSI standards for short-time thermal capabilities for cylindrical rotor machines [2], with margin between the relay characteristic and the capability curve. The settings are to be chosen such that the scheme will not trip below 115% full load current yet provides tripping in a prescribed time for overloads above 115% of full load current. A recommended coordination for the tripping scheme is 7.0 seconds at 226% full load current.

The excitation system provides no functions for stator thermal protection.

The over-current elements are not enabled in the generator protection.

No changes are required.

6 GENERATOR RELAY LOADABILITY ASSESSMENT

NERC Standard PRC-025 [14] has been instated to prevent unnecessary tripping of generators during system disturbances for conditions that do not pose a risk of damage to the associated equipment. The scope of this standard includes load-sensitive protection relaying on all devices which support the transfer of energy between the generator and the Bulk Electric System (BES). This includes the generating unit(s), generator step-up (GSU) transformer(s), any unit auxiliary transformer(s) (UAT) that supplies overall auxiliary power necessary to keep the generating unit(s) online, and equipment connecting the GSU transformer(s) to the transmission system that is used exclusively to export energy to the BES. Review of relevant protective relay settings has been performed to confirm proper coordination with the requirements prescribed NERC Standard.

A list of relays of interest to the NERC PRC-025 Standard are shown in Table A1.The ratings of the equipment within the scope of this study are listed in Table A2. These ratings were used in the calculations presented by the NERC standard to determine the maximum allowable impedance reach for phase distance relay (21) elements and the minimum allowable pickup current for phase overcurrent relay (50/51/67) elements.

6.1 Generator Loadability

NERC Standard PRC-025 [14] provides requirements for phase distance relay (21) elements that are applied to synchronous generating units are directed towards the Transmission System as well as phase time overcurrent relay (51) or voltage-restrained phase time overcurrent relay (51V-R) elements that are applied to synchronous generating units.

The phase distance relay (21) element has an impedance characteristic that is set within the maximum allowable impedance reach prescribed by NERC Standard PRC-025. The scheme meets the requirements of NERC Standard PRC-025, as shown in Appendix D5.

No changes are required.

6.2 GSU Transformer Loadability

NERC Standard PRC-025 [14] provides requirements for phase distance relay (21) elements that are applied to either side of the GSU transformer and directed towards the Transmission System, phase time overcurrent relay (51) elements that are applied to either side of the GSU transformer, and phase directional time overcurrent relay (67) elements that are applied to either side of the GSU transformers and directed towards the Transmission System. There are also requirements for supervisory phase overcurrent relay (50) elements that are applied to the high-voltage side of the GSU transformer as well as for supervisory phase directional overcurrent relay (67) elements that are applied to the high-voltage side of the GSU transformer and directed towards the Transmission System. The supervisory relay elements must be associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications.

The GSU transformer is not equipped with relay elements of interest to NERC Standard PRC-025. No changes are required.

6.3 Unit Auxiliary Transformer Loadability

NERC Standard PRC-025 [14] provides requirements for phase time overcurrent relay (51) elements applied at the high-voltage side terminals of UAT(s) that are critical to operation once the unit(s) are released to dispatch, operating under normal conditions. Only relays that cause the associated generator(s) to trip due to generator lockout or direct trip of the generator main breaker are within the scope of this study. Relays protecting start-up, standby, and reserve UATs are not subject to NERC Standard PRC-025 requirements.

Excitation transformer protective relay elements are not part of the scope of NERC Standard PRC-025.

The UATs are not equipped with relay elements of interest to NERC Standard PRC-025. No changes are required.

6.4 Switchyard Equipment Loadability

NERC Standard PRC-025 [14] provides requirements for phase distance relay (21) elements that are applied to equipment connecting the GSU transformer(s) to the Transmission System and directed towards the Transmission System, phase time overcurrent relay (51) elements that are applied to equipment connecting the GSU transformer(s) to the Transmission System, and phase directional time overcurrent relay (67) elements that are applied to equipment connecting the GSU transformer(s) to the Transmission System and

directed towards the Transmission System. There are also requirements for supervisory phase overcurrent relay (50) elements that are applied to equipment connecting the GSU transformer(s) to the Transmission System as well as for supervisory phase directional overcurrent relay (67) elements that are applied to equipment connecting the GSU transformer(s) to the Transmission System and directed towards the Transmission System. The supervisory relay elements must be associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications.

The phase distance relay (21) element has an impedance characteristic that is set within the maximum allowable impedance reach prescribed by NERC Standard PRC-025. The scheme meets the requirements of NERC Standard PRC-025, as shown in Appendix D6.

The supervisory phase overcurrent relay (50) element has a pickup current that is set greater than the minimum allowable pickup current prescribed by NERC Standard PRC-025. The scheme meets the requirements of NERC Standard PRC-025, as shown in Appendix D6.

No changes are necessary to meet NERC Standard PRC-025 requirements.

7 REFERENCES

1. *IEEE Recommended Practice for Excitation System Models for Power System Stability Studies*, IEEE Std 421.5.

2. *Requirements for Cylindrical-Rotor 50 and 60 Hz Synchronous Generators Rated 10 MVA and Above*, ANSI/IEEE Std. C50.13.

3. *IEEE Guide for AC Generator Protection*, IEEE Standard C37.102.

4. *Verification of Generator Gross and Net Reactive Power Capability*, NERC Standard MOD-025-2.

5. *Verifications of Models and Data for Generator Excitation System Functions*, NERC Standard MOD-026-1.

6. *Verification of Models and Data for Turbine/Generator Speed/Load Control Functions*, NERC Standard MOD-027-1.

7. *Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection*, NERC Standard PRC-019-2, Version 2.

8. *Generator Protective System Performance During Frequency and Voltage Excursions*, NERC Standard PRC-024-2.

9. *Generator Relay Loadability*, NERC Standard PRC-025-1.

10. *Generator Operation for Maintaining Network Voltage Schedules*, NERC Standard VAR-002-4.

11. *WECC Generator Testing and Model Verification of the Laramie River Station Unit 2*, Steven A Barnes, GE Energy, Sept 21, 2010

12. *IEEE Tutorial Course Power System Stabilization Via Excitation Control*, Presented at the IEEE Power Engineering Society General Meeting, Tampa Florida, 28th June 2007.

13. *Power system Stabilizer Design and Performance*, VAR-502-WECC-0, April 2004.

14. *Generator Relay Loadability*, NERC Standard PRC-025-1

15. C. Concordia, *Steady-State Stability of Synchronous Machines as Affected by Voltage-Regulator Characteristics*, Transactions of the AIEE, vol. 63, no. 5, pp. 215-220, May 1944 http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=5058926&isnumber=5058924

APPENDIX A: MODELS/RATING NAMEPLATES

A1 Equipment Identification

Equipment	Manufacturer	Model	Serial #
Generator	General Electric		180X842
Main Exciter	General Electric	EX2100	
Voltage Regulator	General Electric	EX2100	
PSS	General Electric	EX2100	
Governor	Emerson	Ovation	
Turbine	General Electric	Tandem-Compound, 2 Cylinders	170X842
GSU	McGraw-Edison		C-05550-5-3
UAT	Federal Pacific Electric Company		50543-4/3/2 (A/B/C)
PPT	ABB		
Protection Device	GE	G60 - Generator Protection	
Protection Device	GE T60	T60 - GSU Protection	
Protection Device	GE T60	T60 - AUT Protection	
Protection Device	GE T35	L35 - Backup Protection	
Protection Device	GE L90	L90 - Line Protection	

A2 Ratings

A2.1 Generator

Description	Parameter	Value	Units
Generator Base MVA	MBASE	690	MVA
Generator Stator Base Voltage	Etbase	24	kV
Generator Stator Base Current	Itbase	16.6	kA
Generator Rated Speed	rpm	3600	rpm
Rated Power Factor	pf	0.9	
Rated Field Current (rated MVA and pf)	IfgRated	4692	Adc
Rated Field Voltage (rated MVA and pf)	EfgRated	500	Vdc
Calculated No-Load Field Current	Ifgnlcalc	2025	Adc
Generator Base Field Current	IfgBase	1771	Adc
Generator Base Field Voltage	EfgBase	189	Vdc
Generator Base Field Resistance	RfgBase	0.106	Ω
Generator Base Field Temperature	TfgBase	100	°C
Generator Stator Base Impedance	Zbase	0.835	Ω

A2.2 Excitation Power Supply

Description	Parameter	Value	Units
Apparent Power of PPT/PMG	kVA	8061	kVA
Primary Voltage	kV HV	24	kV
Secondary Voltage/PMG loaded voltage	kV LV	1090	Vac
Impedance	Z	6.3	%
Number of phases	Phases	3	
Frequency	Freq	60	Hz

A2.3 Generator Step-up Transformer

Description	Parameter	Value	Units
LV Rated Voltage	GSU_LV_Rated	23.4	kV
HV Rated Voltage	GSU_HV_Rated	345	kV
Rated MVA 1	ONAN	630	MVA
Rated MVA 2	ONAF1	706	MVA
Rated MVA 3	ONAF2	100	MVA
GSU Resistance	GSU_R	0	%
GSU Reactance	GSU_X	8.1	%
Tap Position	GSU_Tap	100	%
Base for Impedance	GSU_MVA	630	MVA
Winding Connection		LV:Delta- HV:Grounded-Y	

System HV Nominal Voltage	E_sys	345	kV

Notes:

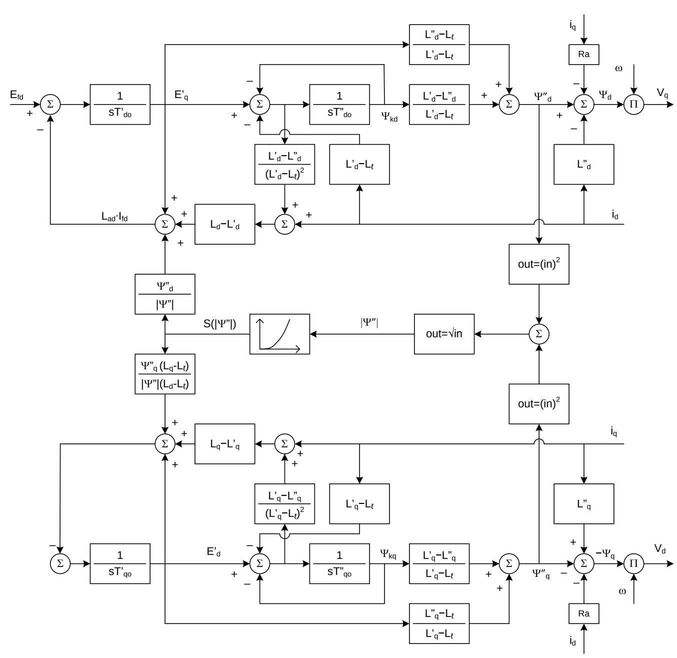
1. The system nominal voltage is not part of the GSU rating, but is necessary information for protection coordination calculations

A3 Generator Model

Generator Model GENROU: Round Rotor Generator Model PSLF Model

Description	Parameter	Value	Units
d-axis OC transient time constant	T'do (>0)	4	s
d-axis OC sub-transient time constant	T"do (>0)	0.035	s
q-axis OC transient time constant	T'qo (>0)	0.495	s
q-axis OC sub-transient time constant	T"qo (>0)	0.067	s
Inertia	H	2.766	MW.s/MVA
Damping	D	0	pu
d-axis synchronous reactance	Xd	1.68	pu
q-axis synchronous reactance	Xq	1.564	pu
d-axis transient reactance	X'd	0.289	pu
q-axis transient reactance	X'q	0.464	pu
subtransient reactance	X"d=X"q	0.235	pu
leakage reactance	Xl	0.228	pu
saturation factor at 1.0 pu Et	S(1.0)	0.143	pu
saturation factor at 1.2 pu Et	S(1.2)	0.336	pu
stator resistance	Ra	0.0032	pu
compounding resistance	Rcomp	0	pu
compounding reactance	Xcomp	0	pu

Notes:



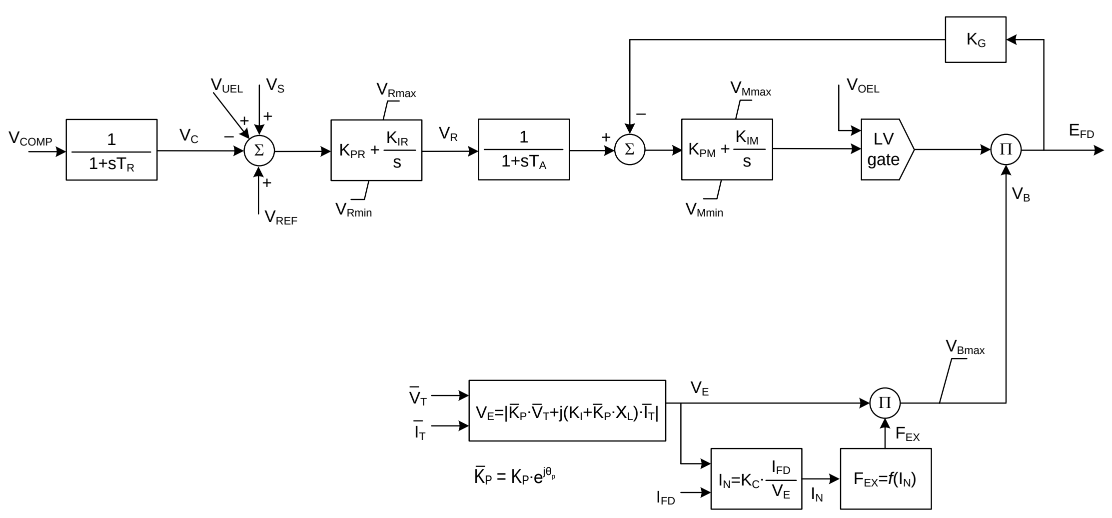
A4 Excitation System Model

Excitation Model IEEE 421.5 Std. ST4B
PSLF Model ESST4B

Description	Parameter	Value	Units
voltage transducer time constant	Tr	0	s
AVR proportional gain	Kpr	5.85	pu
AVR integral gain	Kir	5.85	pu
AVR time constant	Ta	0.01	s
AVR maximum output	Vrmax	1.00	pu
AVR minimum output	Vrmin	-0.80	pu
inner loop proportional gain	Kpm	1	pu
inner loop integral gain	Kim	0	pu
inner loop regulator maximum output	Vmmax	1.00	pu
inner loop regulator minimum output	Vmmin	-0.80	pu
inner loop feedback gain	Kg	0	pu
potential source gain	Kp	7.80	pu
phase angle of potential source	Angp	0	degrees
current source gain	Ki	0	pu
rectifier regulation factor	Kc	0.14	pu
leakage reactance	Xl	0	pu
maximum excitation voltage	Vbmax	9.75	pu
maximum inner loop feedback	Vgmax	999	pu

Notes:

1. The PSLF program requires the smallest time constant to be greater than 4 times the integration time step. For TR, TA < (4 x integration step), set TA=0 and TR=smallest allowable value. Kestrel suggests using 0.017 seconds as the smallest allowable value if the integration time step is 1/4 cycle.



A5 Power System Stabilizer Model

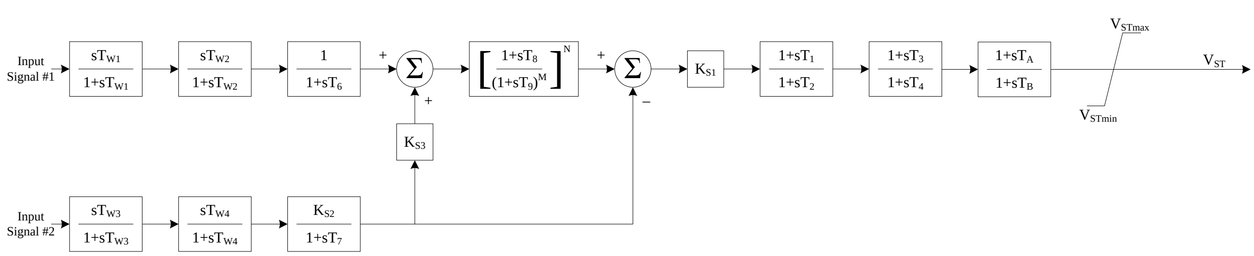
Power System Stabilizer Model IEEE 421.5 Std. PSS2A
PSLF Model PSS2A

Description	Parameter	Value	Units
first stabilizer input signal code	J1	1	
remote bus for first input signal	K1	0	
second stabilizer input signal code	J2	3	
remote bus for second input signal	K2	0	
input #1 first washout time constant	Tw1 (>0)	5	s
input #1 second washout time constant	Tw2	5	s
input #2 first washout time constant	Tw3(>0)	5	s
input #2 second washout time constant	Tw4	0	s
input #1 measurement time constant	T6	0	s
input #2 lag time constant	T7	5	s
input #2 gain	Ks2	0.9038	pu
gain	Ks3	1	pu
gain	Ks4	1	pu
ramp tracking filter numerator time constant	T8	0.5	s
ramp tracking filter denominator time constant	T9 (>0)	0.1	s
ramp track filter overall exponent	N	1	
ramp track filter denominator exponent	M	5	
PSS main gain	Ks1	8	pu
1st lead-lag numerator time constant	T1	0.1	s
1st lead-lag denominator time constant	T2	0.025	s
2nd lead-lag numerator time constant	T3	0.1	s
2nd lead-lag denominator time constant	T4	0.02	s
PSS max. output limit	Vstmax	0.1	pu
PSS min. output limit	Vstmin	-0.1	pu
4th lead-lag num. gain	a	1	pu
4th lead-lag num. time constant	Ta	0	s
4th lead-lag den. time constant	Tb	0	s

frequency compensation reactance	Xq comp	0.269	pu

Notes:

1. First input is compensated frequency calculated with the reactance Xq comp. The simulation model uses speed deviation as the first input, as compensated frequency is not available.
2. The parameter Tw4 is zero to indicate that the block is by-passed (block output=input)



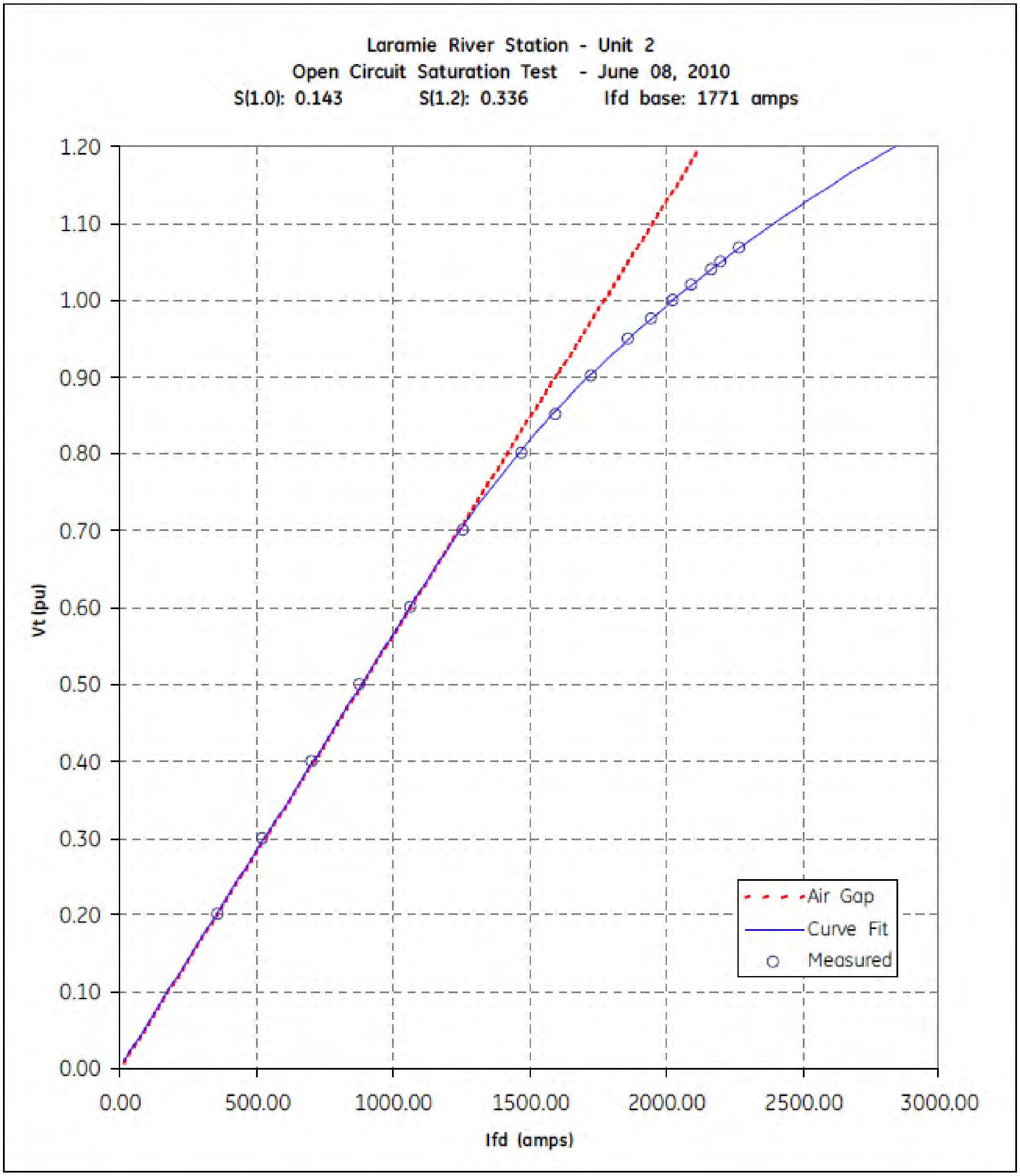
A6 Turbine Governor Model

*The unit should be represented in system studies as fixed mechanical power sources. The representation of a constant mechanical power from the turbine is usually automatically assumed when no explicit turbine/speed governor model is provided.

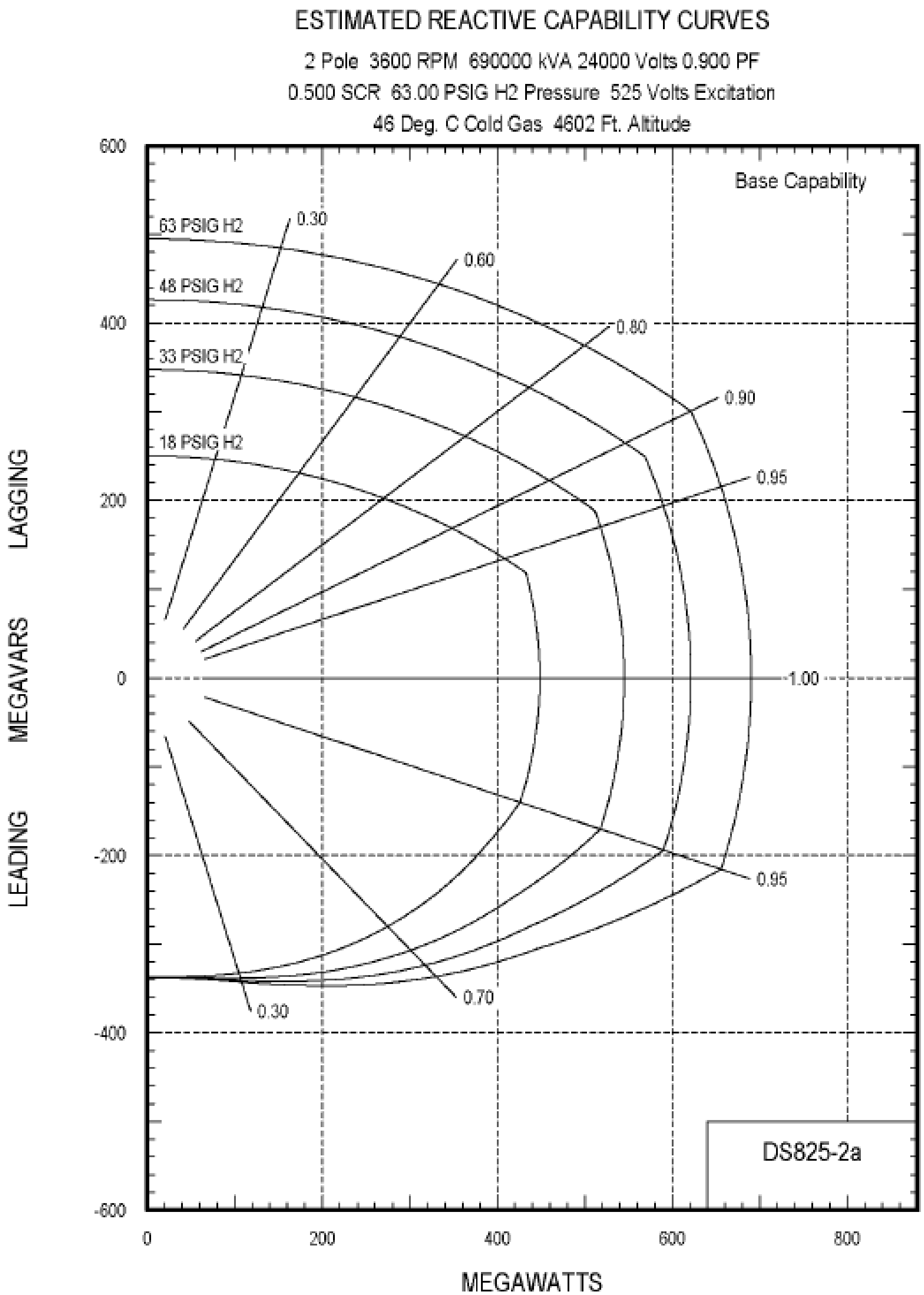
Thus, the fact that no explicit model has been provided implies that these units will be represented as fixed mechanical power sources and, as such, the requirements from NERC Std. MOD-027 are met.

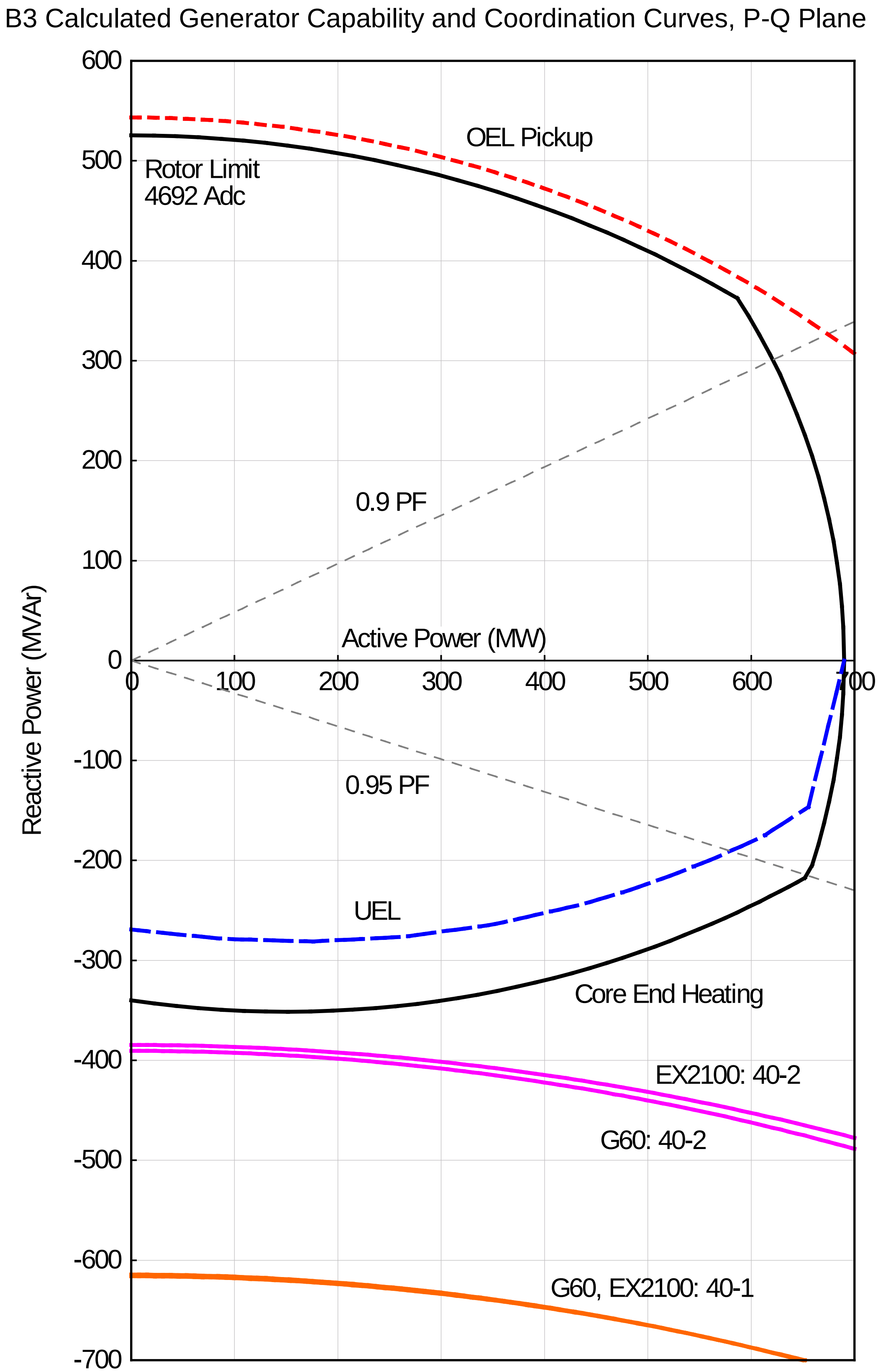
APPENDIX B: CHARACTERISTIC CURVES

B1 Manufacturer's Generator Open Circuit Saturation Characteristic

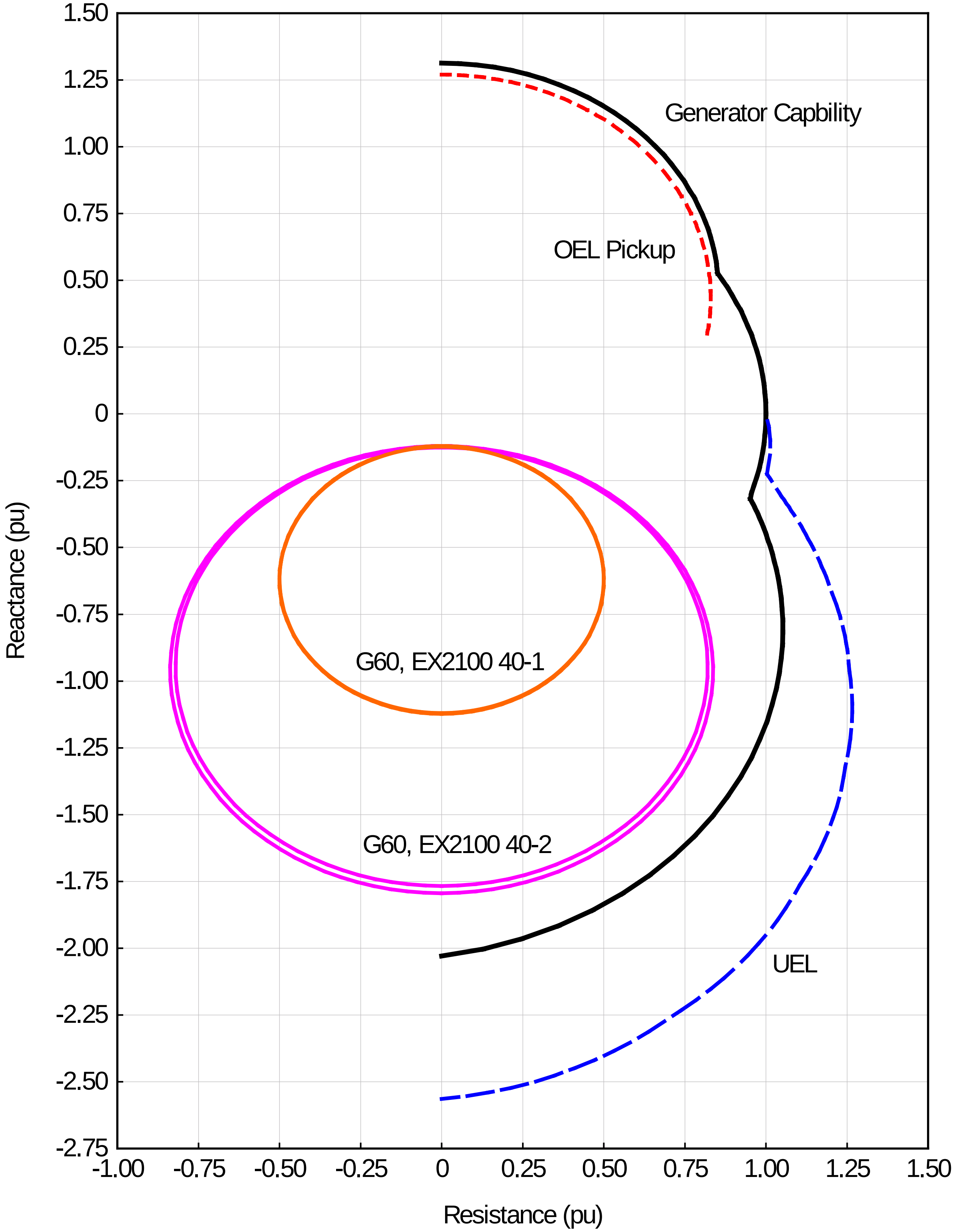


B2 Manufacturer's Generator Capability Curves

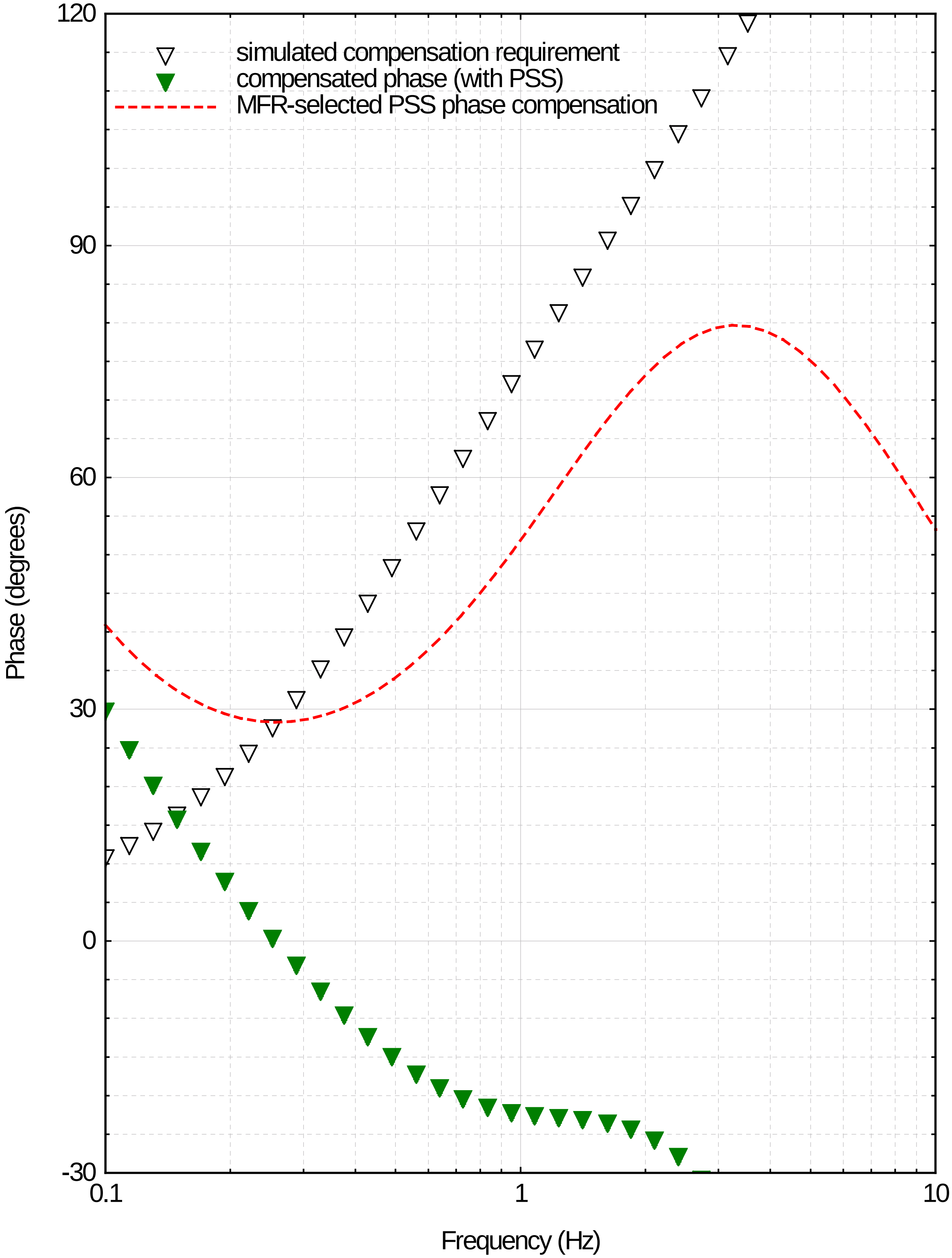



B3 Calculated Generator Capability and Coordination Curves, P-Q Plane
600
500
400
300
200
100
0
-100
-200
-300
-400
-500
-600
-700
0
100
200
300
400
500
600
700
Reactive Power (MVAr)
Active Power (MW)
OEL Pickup
Rotor Limit
4692 Adc
0.9 PF
0.95 PF
UEL
Core End Heating
EX2100: 40-2
G60: 40-2
G60, EX2100: 40-1

B4 Calculated Generator Capability and Coordination Curves, R-X Plane

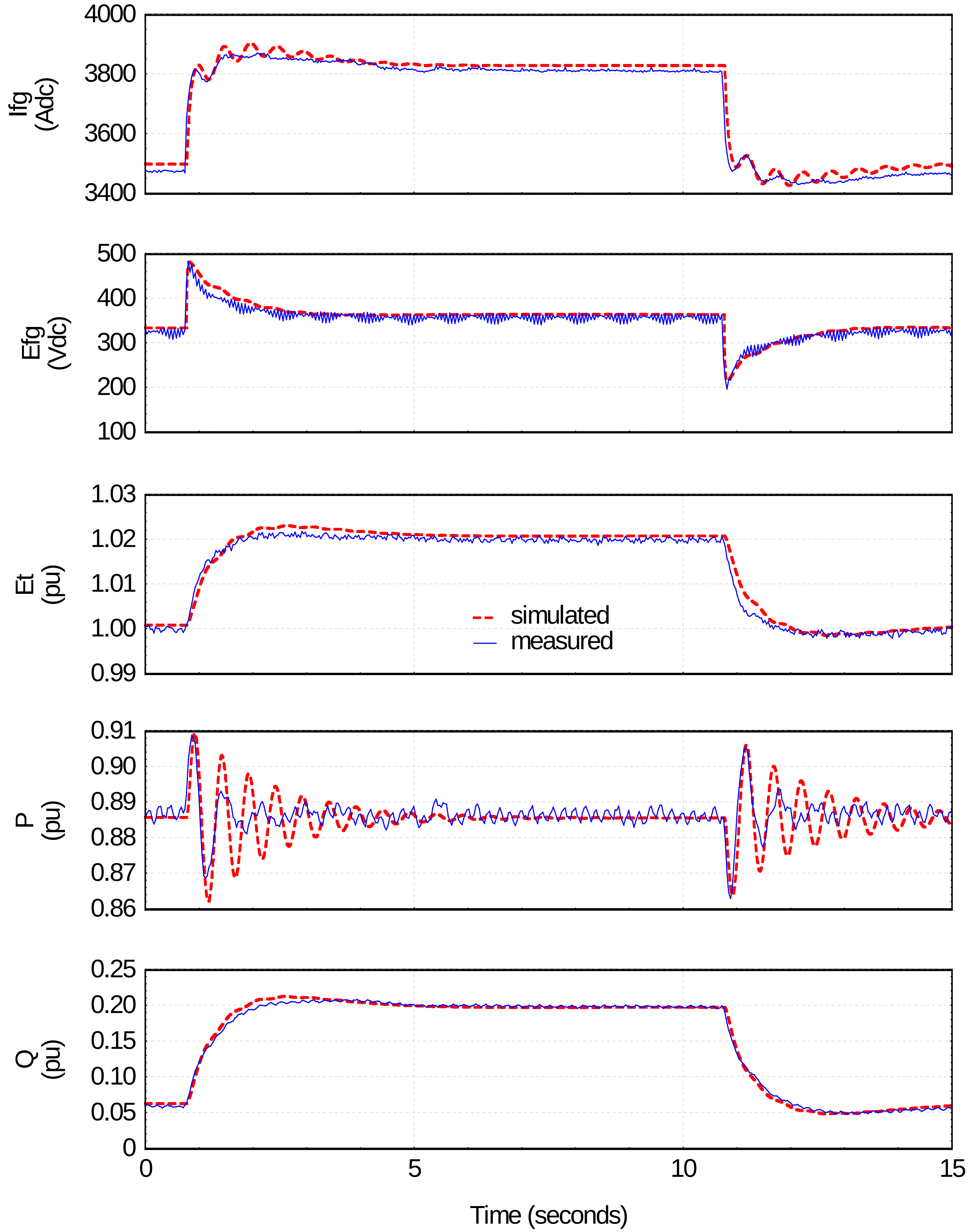


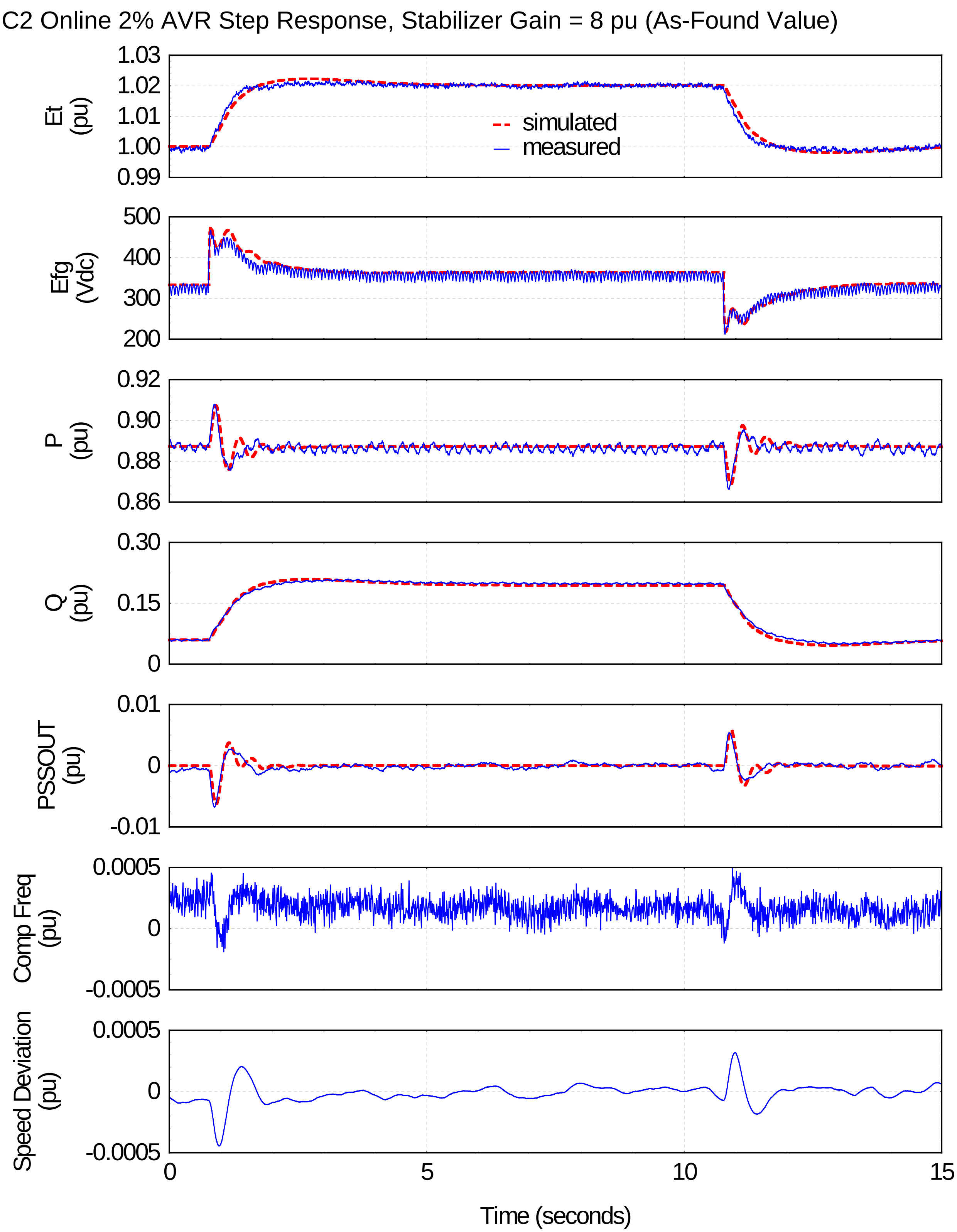
B5 Stabilizer Phase Compensation



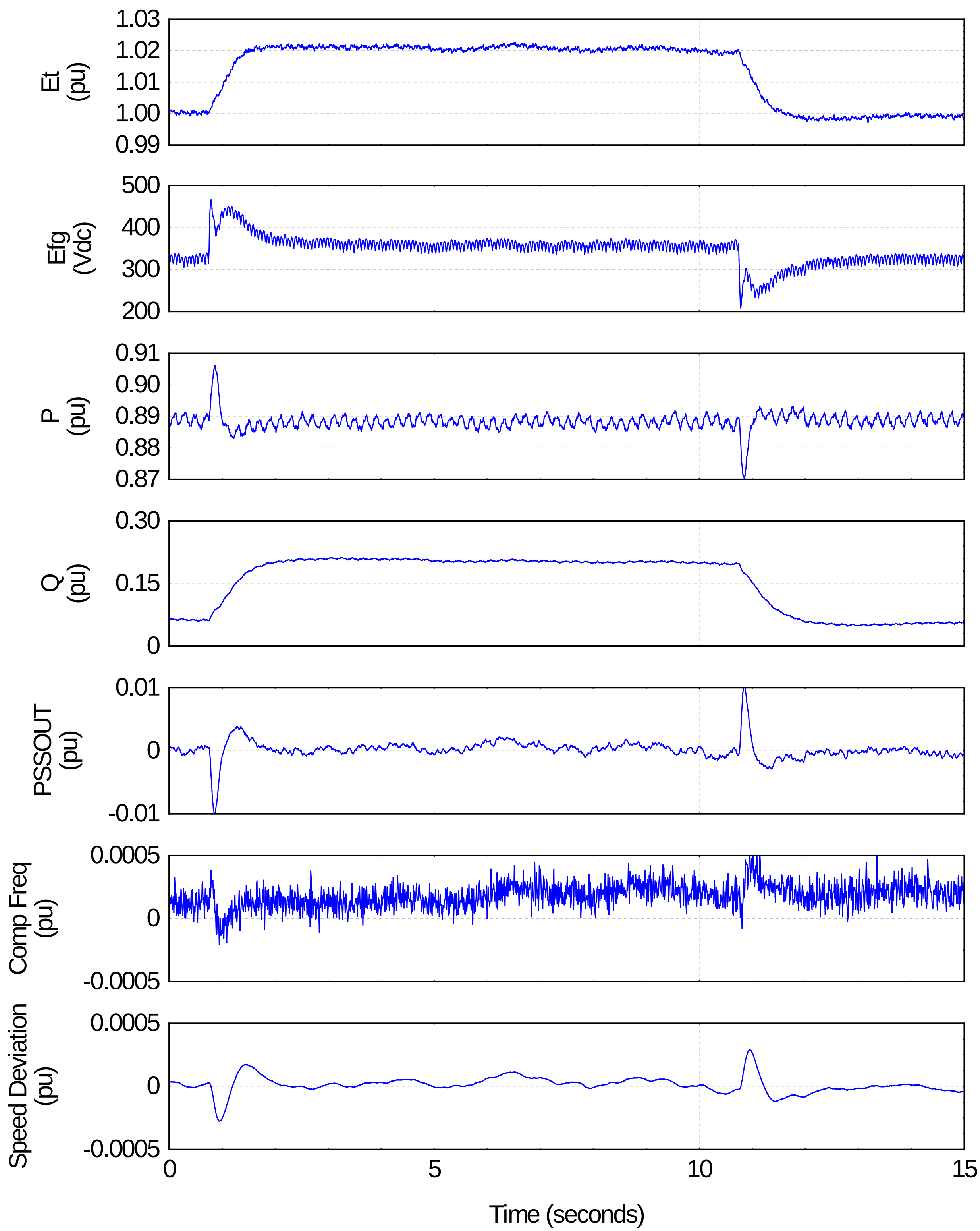
APPENDIX C: MEASUREMENTS

C1 Online 2% AVR Step Response, Stabilizer Gain = 0 pu




C2 Online 2% AVR Step Response, Stabilizer Gain = 8 pu (As-Found Value)
Et (pu)
1.03
1.02
1.01
1.00
0.99
simulated
measured
Efg (Vdc)
500
400
300
200
P (pu)
0.92
0.90
0.88
0.86
Q (pu)
0.30
0.15
0
PSSOUT (pu)
0.01
0
-0.01
Comp Freq (pu)
0.0005
0
-0.0005
Speed Deviation (pu)
0.0005
0
-0.0005
0
5
10
15
Time (seconds)

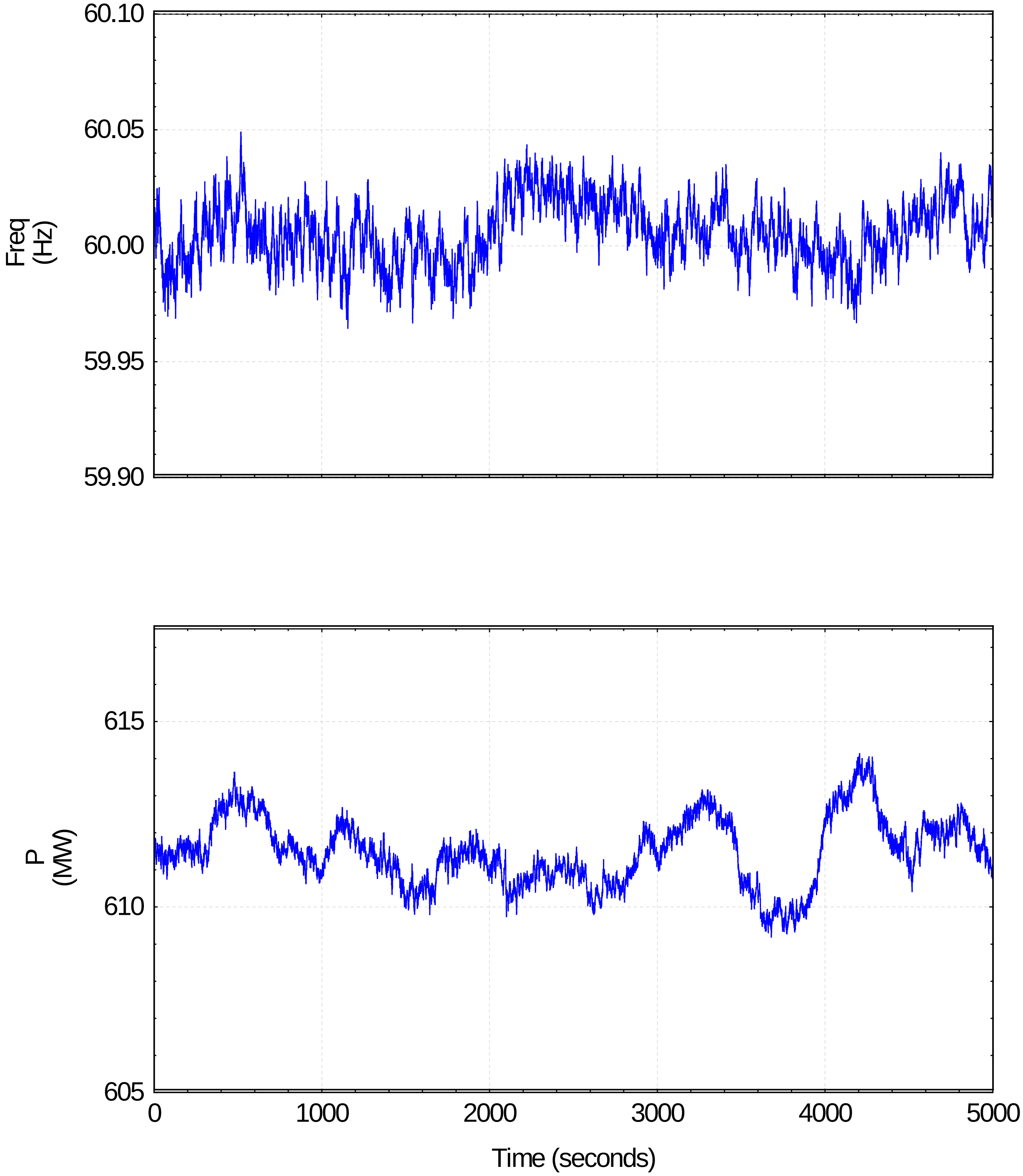
C3 Online 2% AVR Step Response, Stabilizer Gain = 16 pu (2x As-Found Value)



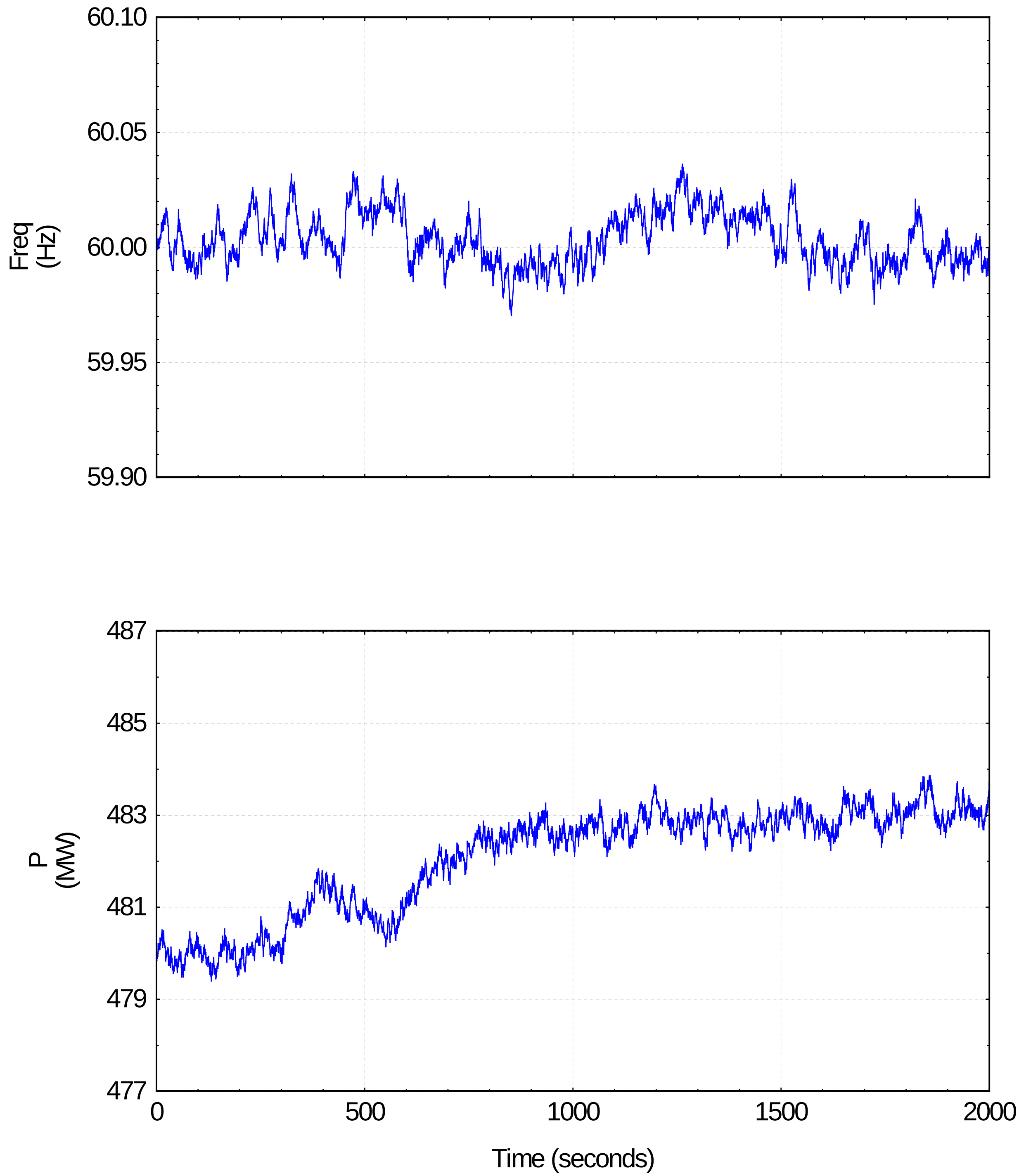
C4 Steady State Measurements

P	Q	Et	Efg	Ifg	Ifg
					calculated
(MW)	(MVAr)	(kV)	(Vdc)	(Adc)	(Adc)
612	-160	23.05	291	3005	3005
612	320	24.93	451	4650	4609
225.7	-258.3	23.1	115	1258	1198
227.3	278.1	25.15	340	3660	3686
610	-30	23.71	330	3260	3301
231	-1	24	208	2244	2268
481	41	24.15	282	3055	3103
482	-190	22.87	218	2400	2397
480	273	25.14	388	4125	4101
290	-31	23.86	203	2260	2261
290	-227	22.8	143	1565	1517
290	300	25.18	355	3830	3875

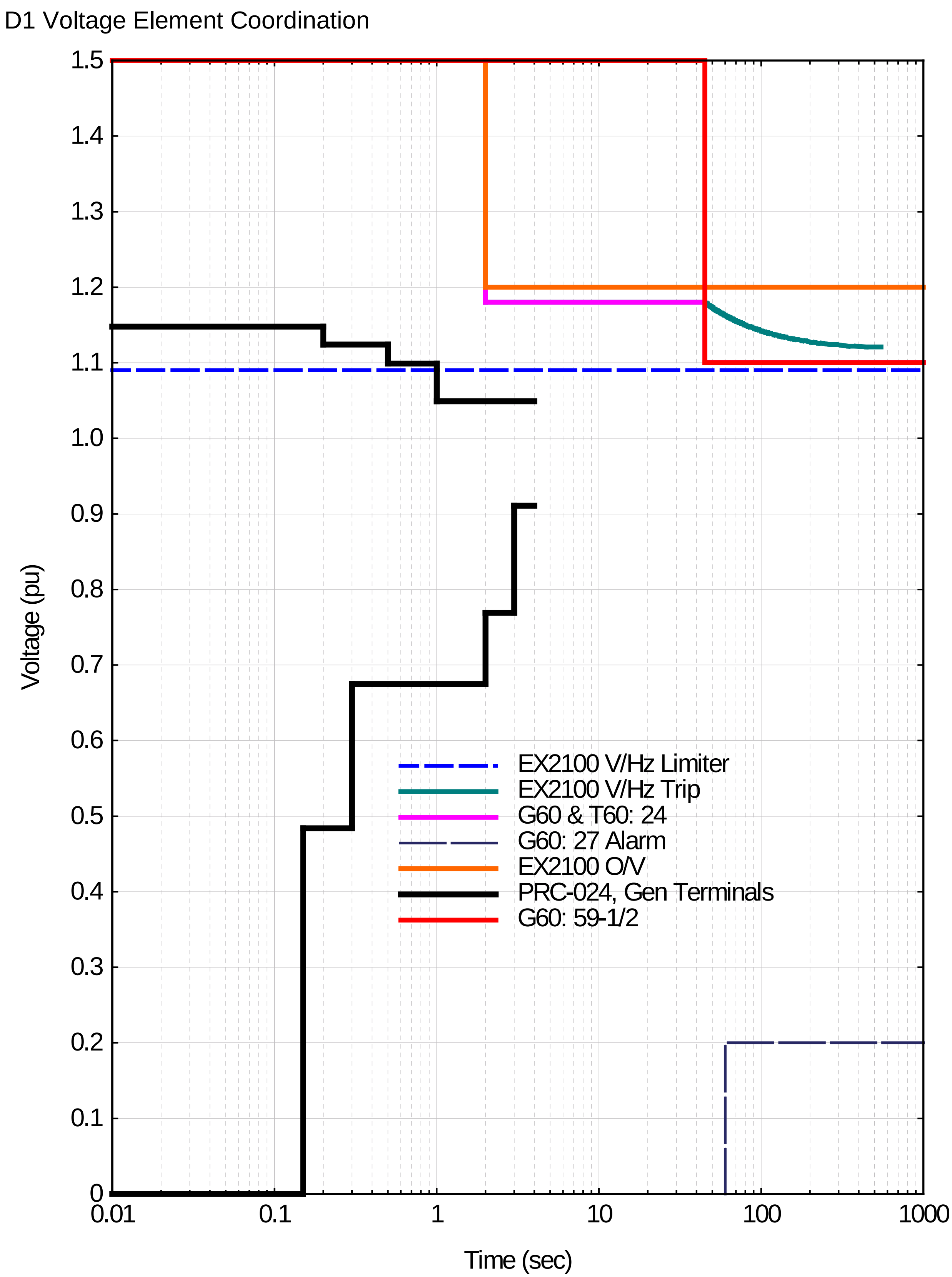
C5 Governor Ambient Measurements, Full Load



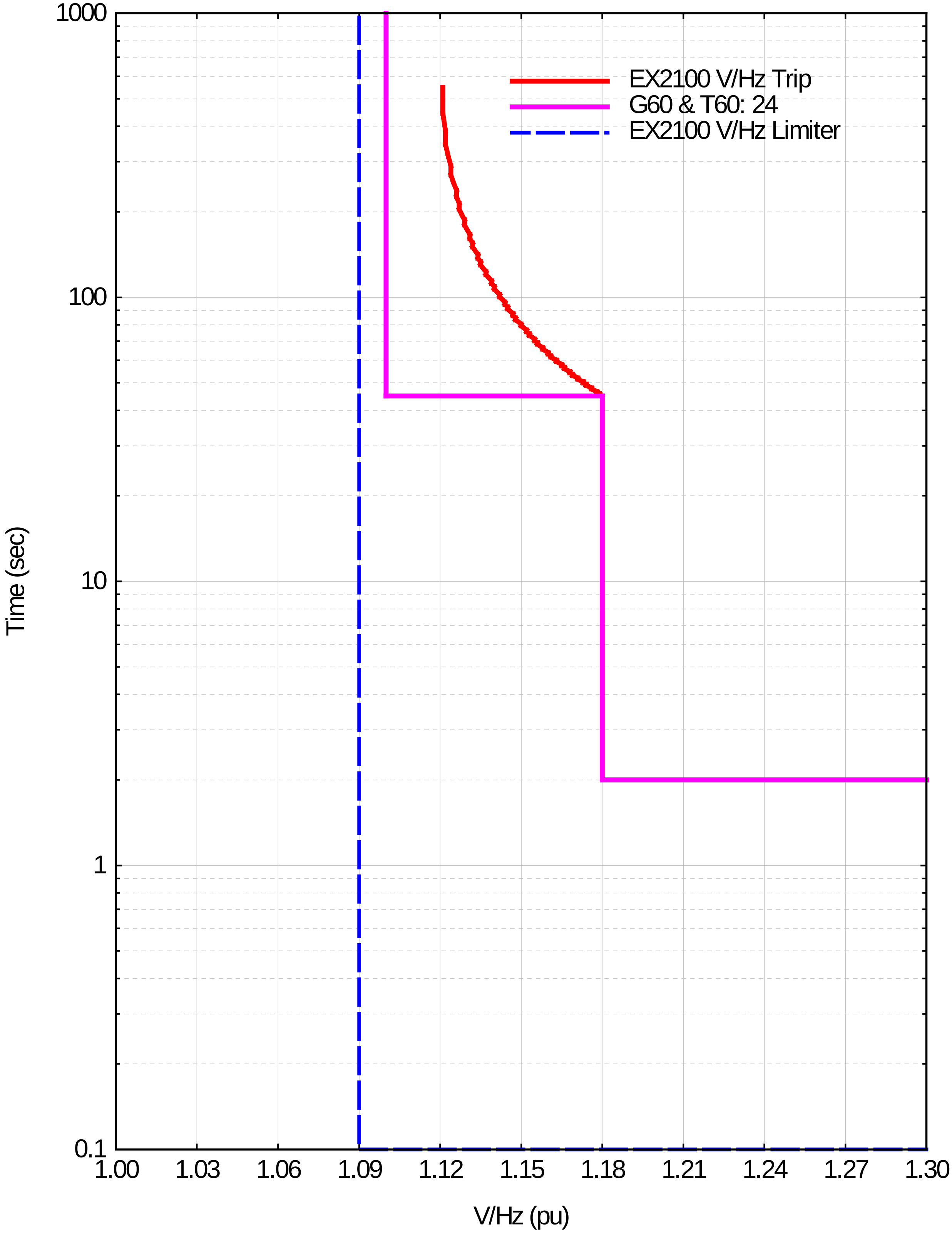
C6 Governor Ambient Measurements, Partial Load

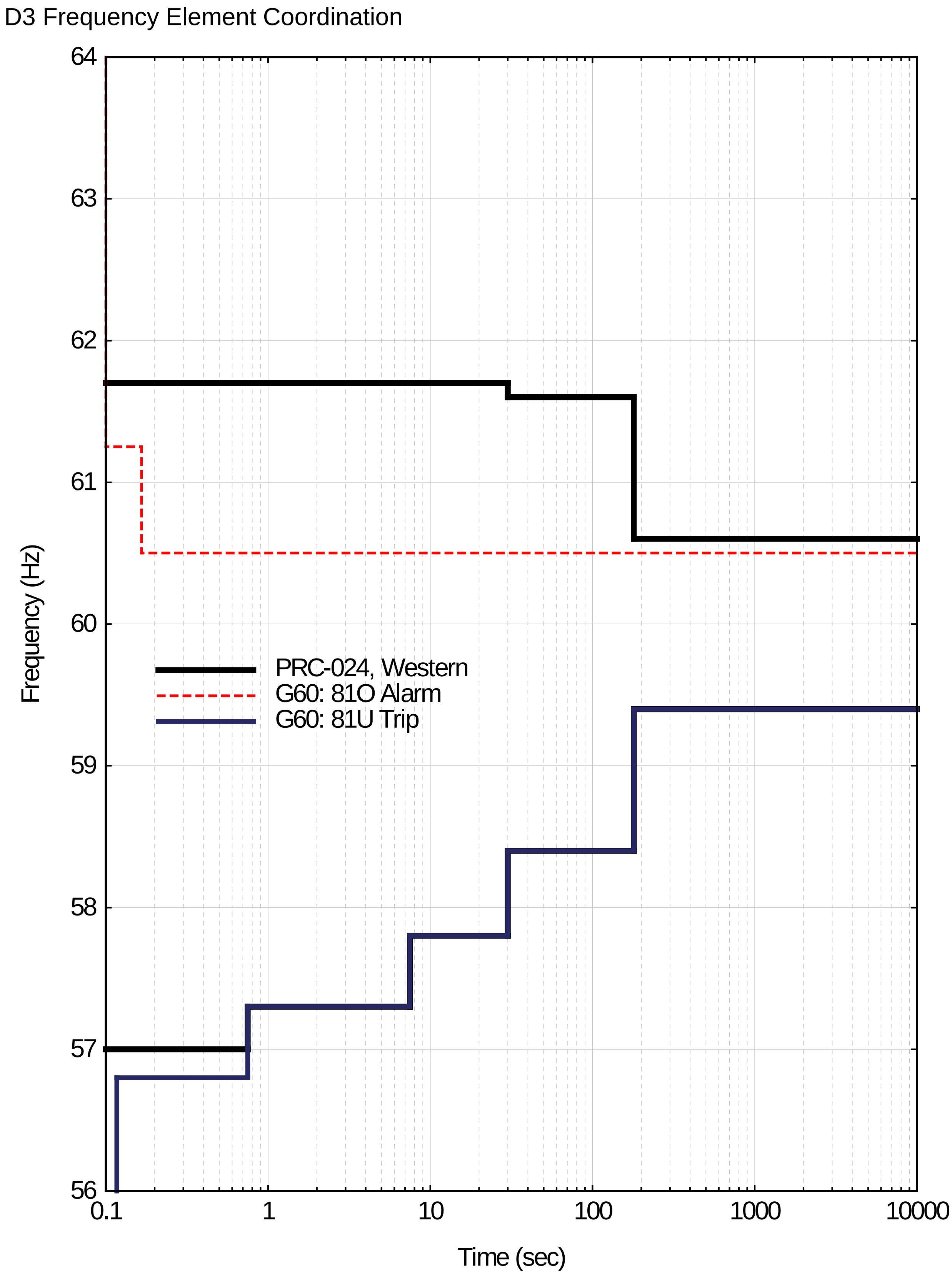


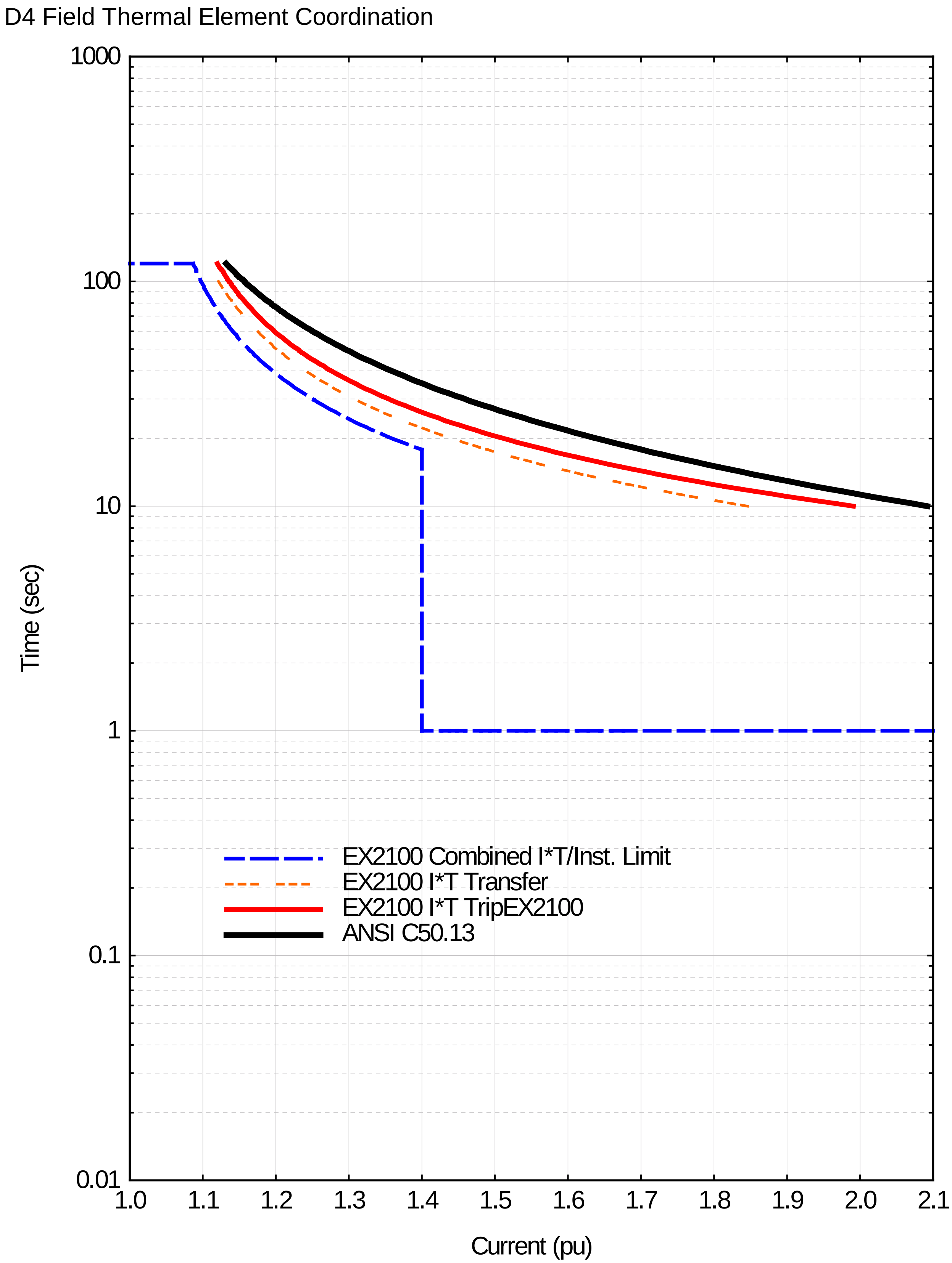
APPENDIX D: PROTECTION COORDINATION


D1 Voltage Element Coordination
Voltage (pu)
1.5
1.4
1.3
1.2
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0.01
0.1
1
10
100
1000
Time (sec)
EX2100 V/Hz Limiter
EX2100 V/Hz Trip
G60 & T60: 24
G60: 27 Alarm
EX2100 O/V
PRC-024, Gen Terminals
G60: 59-1/2

D2 V/Hz Element Coordination




D3 Frequency Element Coordination
Frequency (Hz)
64
63
62
61
60
59
58
57
56
0.1
1
10
100
1000
10000
Time (sec)
PRC-024, Western
G60: 81O Alarm
G60: 81U Trip


D4 Field Thermal Element Coordination
1000
100
10
1
0.1
0.01
Time (sec)
1.0
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
2.1
Current (pu)
EX2100 Combined I*T/Inst. Limit
EX2100 I*T Transfer
EX2100 I*T TripEX2100
ANSI C50.13

D5 Generating Unit Relay Loadability Calculations

D5.1 Maximum Allowable Impedance Reach Calculations

Option 1a: V_{gen} = 22.23 kV, S = 570 + j931.5 MVA, Z Ratio = 0.05
Yields $\theta_{transient\ load\ angle}$ = 58.5°, Z_{pri} = 0.453 Ohms, Z_{sec} = 9.05 Ohms-secondary
$Z_{max} = Z_{sec} / (115\% \cdot \cos(\theta_{MTA} - \theta_{transient\ load\ angle}))$

Option 1b: V_{bus} = 22.67 kV, S = 570 + j931.5 MVA, Z Ratio = 0.05
Yields $\theta_{transient\ load\ angle}$ = 58.5°, Z_{pri} = 0.471 Ohms, Z_{sec} = 9.412 Ohms-secondary
$Z_{max} = Z_{sec} / (115\% \cdot \cos(\theta_{MTA} - \theta_{transient\ load\ angle}))$

Option 1b is used, since it provides the least restrictive requirement on maximum allowable impedance reach. *Note that the maximum allowable impedance reach is dependent on the maximum torque angle (θ_{MTA}) setting.*

G60: 21-1 angle = 89°, reach = 1.33 < 9.5 Ohms-secondary → ***PRC-025 Compliant***
G60 21-2 angle = 86°, reach = 8.3 < 9.22 Ohms-secondary → ***PRC-025 Compliant***
G60 21-3 angle = 89°, reach = 4.92 < 9.5 Ohms-secondary → ***PRC-025 Compliant***

D6 GSU Transformer (High-Voltage Side) Relay Loadability Calculations

D6.1 Maximum Allowable Impedance Reach Calculations

Option 14a: V_{bus} = 293.25 kV, S = 570 + j745.2 MVA, Z Ratio = 7.5
Yields $\theta_{transient\ load\ angle}$ = 52.6°, Z_{pri} = 91.66 Ohms, Z_{sec} = 12.221 Ohms-secondary
$Z_{max} = Z_{sec} / (115\% \cdot \cos(\theta_{MTA} - \theta_{transient\ load\ angle}))$

Note that the maximum allowable impedance reach is dependent on the maximum torque angle (θ_{MTA}) setting.

L90: 21-1 angle = 89°, reach = 1.07 < 13.21 Ohms-secondary → ***PRC-025 Compliant***

D6.2 Minimum Allowable Pickup Current Calculations

Option 15a: V_{bus} = 293.25 kV, S = 570 + j745.2 MVA, CT Ratio = 240
Yields I_{pri} = 1847.131 A_{AC}, I_{sec} = 7.696 A_{AC}-secondary
I_{min} = 115% * I_{sec} = 8.85 A_{AC}-secondary

The minimum allowable pickup current for an element in this category is **8.85 A_{AC}-secondary**.

L90: 50 pickup = 9.72 > 8.85 A_{AC}-secondary → ***PRC-025 Compliant***

APPENDIX E: REACTIVE CAPABILITY FORMS

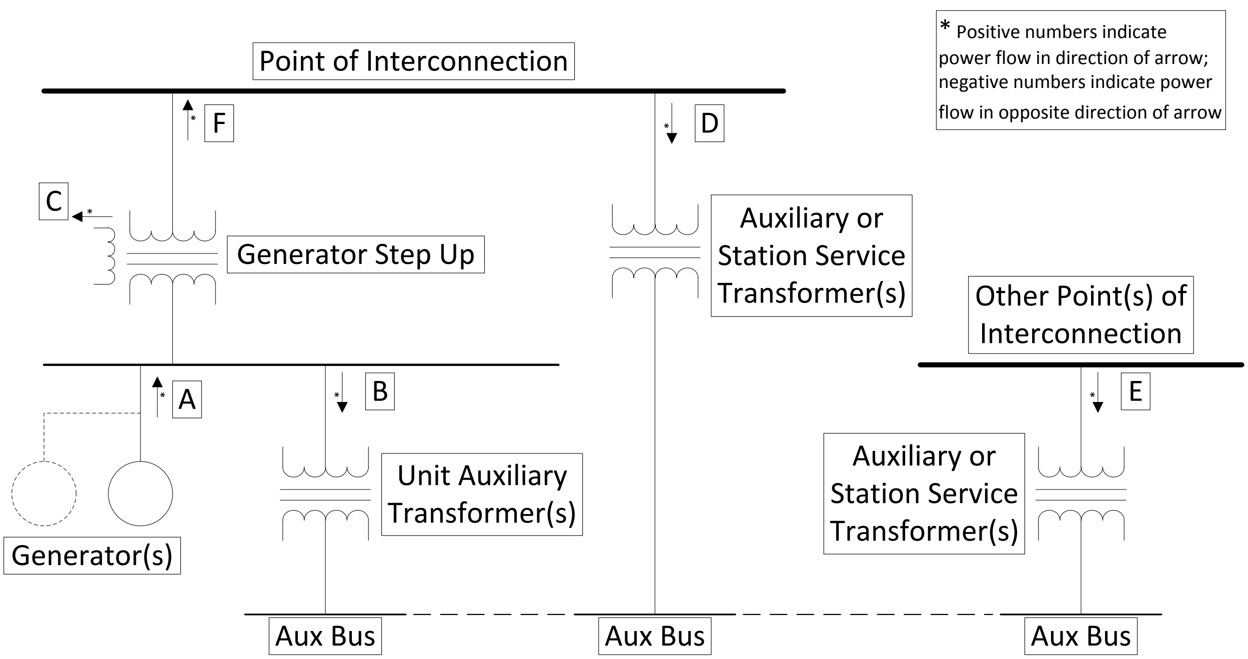
E1 NERC Reactive Capability Form

MOD-025 Attachment 2

Company: Basin Electric   Reported By: On:
Plant: Laramie River Station   Unit No.: 2

Check all that apply:
☒Under-Excited Minimum Load Reactive Power Verification
☒Over-Excited Minimum Load Reactive Power Verification
☒Under-Excited Maximum Load Reactive Power Verification
☒Over-Excited Maximum Load Reactive Power Verification
☒Real Power Verification
☒Staged Test Data
☐Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Under-Excited Minimum Load

Point	Voltage	Real Power	Reactive Power	Comments
A	**23.1 kV**	**226.0 MW**	**-258.3 MVAR**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Indicate any calculated values, if any:				
B	**6.9 kV**	**26.0 MW**	**13.0 MVAR**	Sum multiple unit auxiliary transformers.
Indicate any calculated values, if any: P, Q calc'd from current				
C	N/A	N/A	N/A	Sum multiple tertiary Loads, if any.
Indicate any calculated values, if any:				
D	N/A	N/A	N/A	Sum multiple auxiliary and station service transformers.
Indicate any calculated values, if any:				
E	N/A	N/A	N/A	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
Indicate any calculated values, if any:				
F	**357.8 kV**	**196.0 MW**	**-306.0 MVAR**	Net unit capability.
Indicate any calculated values, if any:				

Over-Excited Minimum Load

Point	Voltage	Real Power	Reactive Power	Comments
A	**25.2 kV**	**227.0 MW**	**278.0 MVAR**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Indicate any calculated values, if any:				
B	**6.9 kV**	**26.0 MW**	**13.0 MVAR**	Sum multiple unit auxiliary transformers.
Indicate any calculated values, if any: P, Q calc'd from current				
C	N/A	N/A	N/A	Sum multiple tertiary Loads, if any.
Indicate any calculated values, if any:				
D	N/A	N/A	N/A	Sum multiple auxiliary and station service transformers.
Indicate any calculated values, if any:				
E	N/A	N/A	N/A	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
Indicate any calculated values, if any:				
F	**364.2 kV**	**211.0 MW**	**230.0 MVAR**	Net unit capability.
Indicate any calculated values, if any:				

Under-Excited Maximum Load

Point	Voltage	Real Power	Reactive Power	Comments
A	**23.1 kV**	**612.0 MW**	**-160.0 MVAR**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Indicate any calculated values, if any:				
B	**6.8 kV**	**42.0 MW**	**22.0 MVAR**	Sum multiple unit auxiliary transformers.
Indicate any calculated values, if any: P, Q calc'd from current				
C	N/A	N/A	N/A	Sum multiple tertiary Loads, if any.
Indicate any calculated values, if any:				
D	N/A	N/A	N/A	Sum multiple auxiliary and station service transformers.
Indicate any calculated values, if any:				
E	N/A	N/A	N/A	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
Indicate any calculated values, if any:				
F	**357.7 kV**	**566.0 MW**	**-247.8 MVAR**	Net unit capability.
Indicate any calculated values, if any:				

Over-Excited Maximum Load

Point	Voltage	Real Power	Reactive Power	Comments
A	**24.9 kV**	**612.0 MW**	**320.0 MVAR**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Indicate any calculated values, if any:				
B	**6.9 kV**	**43.0 MW**	**22.0 MVAR**	Sum multiple unit auxiliary transformers.
Indicate any calculated values, if any: P, Q calc'd from current				
C	N/A	N/A	N/A	Sum multiple tertiary Loads, if any.
Indicate any calculated values, if any:				
D	N/A	N/A	N/A	Sum multiple auxiliary and station service transformers.
Indicate any calculated values, if any:				
E	N/A	N/A	N/A	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
Indicate any calculated values, if any:				
F	**359.0 kV**	**574.0 MW**	**211.0 MVAR**	Net unit capability.
Indicate any calculated values, if any:				

Verification Data

Provide data by unit or facility, as appropriate

Data Type	Data Recorded	Last Verification
	1-Hour Lagging	n/a
Gross Reactive Power Capability (*MVAR)	320.00	
Aux Reactive Power (*MVAR)	22.000	
Tertiary Reactive Power (*MVAR)		
[1]Net Reactive Power Capability (*MVAR)	211	
GSU Reactive Power Losses (*MVAR)	87	
Gross Active Power Capability (*MW)	612.0	
Aux Active Power (*MW)	42.000	
Tertiary Active Power (*MW)		
[1]Net Active Power Capability (*MW)	575	

* Values from end of the verification period
[1] Note: Net Capability equals Gross Capability minus Aux Power and Tertiary Power connected at the same bus

Summary of Verification

Verification Date: 15-April-2016
Verification Start Time: 3:00 PM
Verification Stop Time: 11:00 PM
Scheduled Voltage: n/a pu

Transformer Voltage Ratio:
GSU: 23.4:345 kV
Unit Aux: 24:7.2 kV
Station Aux: N/A
Other Aux: N/A

Transformer Tap Setting:
GSU: 1
Unit Aux: +1%, -1%, -0.3%
Station Aux: N/A
Other Aux: N/A

Ambient Conditions at the end of verification period:
Air Temperature (°F): 40
Humidity: N/A
Cooling Water Temp. (°C): n/a
Other Data, as applicable: n/a
Gen. Hydrogen Pressure at Time of Test: 60.45
Date of Last Verification: n/a

Remarks:

Limited by UEL on under-excited tests.
Limited by rated field current on full load, over-excited.
Limited by 105% terminal voltage on min load, over-excited.

APPENDIX F: SETTINGS

F1 Excitation System Settings

Description	Variable Name	Value
Generator		
Rated generator terminal voltage	KV_Rated	24
Rated generator MVA	MVA_Rated	690
Voltage Field Full Load	VFFL	510.6264038
Voltage Field No Load	VFNL_Hot	213.3912048
Amps Field Air-Gap	AFAG	1689
Amps Field No Load	AFNL	1947
Amps Field Full Load	AFFL	4659
Field Resistance at 125°C	RfldAt125C	0.1096
Amps to produce 100mV on the shunt	ShuntAmps	7500
PPT Voltage	PPT_Vrms	1090

Auto Voltage Regulator (AVR)		
Proportional Gain	AVRPGN	5.852577209
Integral Gain	AVRIGN	5.852577209
Reactive Current Compensation (pu)	ASPRCC	0
Volts/Hertz limit (pu)	ASPVHZ	1.090000033
Output Upper Limit (pu)	ASPHLM	1.100000024
Output Upper Limit (fraction of Ed0)	AVRPLM	1
Output Lower Limit (fraction of Ed0)	AVRNLM	-0.800000012

Under Excitation Limiter (UEL)		
UEL Curve Watts Pt. 1	UELX0	0
UEL Curve Watts Pt. 2	UELX1	0.126672462
UEL Curve Watts Pt. 3	UELX2	0.253344923
UEL Curve Watts Pt. 4	UELX3	0.38001737
UEL Curve Watts Pt. 5	UELX4	0.506689847
UEL Curve Watts Pt. 6	UELX5	0.633362293
UEL Curve Watts Pt. 7	UELX6	0.696698546
UEL Curve Watts Pt. 8	UELX7	0.76003474
UEL Curve Watts Pt. 9	UELX8	0.823370934
UEL Curve Watts Pt. 10	UELX9	0.886707246
UEL Curve Watts Pt. 11	UELX10	0.95004338
UEL Curve Vars Pt. 1	UELY0	-0.490012169
UEL Curve Vars Pt. 2	UELY1	-0.503502667
UEL Curve Vars Pt. 3	UELY2	-0.507375658
UEL Curve Vars Pt. 4	UELY3	-0.500835121
UEL Curve Vars Pt. 5	UELY4	-0.483071774
UEL Curve Vars Pt. 6	UELY5	-0.453304201
UEL Curve Vars Pt. 7	UELY6	-0.433677912
UEL Curve Vars Pt. 8	UELY7	-0.410745531
UEL Curve Vars Pt. 9	UELY8	-0.384401828
UEL Curve Vars Pt. 10	UELY9	-0.354571134
UEL Curve Vars Pt. 11	UELY10	-0.3122679
Margin above the plotted curve (pu)	MARGIN	0.100000001
UEL Proportional Gain	UELPGN	0.800000012
UEL Integral Gain	UELIGN	0.5
UEL Output Upper Limit (pu)	UELPLM	0.25
UEL Output Lower Limit (pu)	UELNLM	0
Watts Stator Limit Reference Line Pt. 1	STAT_W1	0.95004338
Watts Stator Limit Reference Line Pt. 2	STAT_W2	1
Vars Stator Limit Reference Line Pt. 1	STAT_V1	-0.212267905
Vars Stator Limit Reference Line Pt. 2	STAT_V2	0

Over Excitation Limiter (OEL) Inverse Time		
Level for field OE trip relay accumulation	OE_PU	4752.180176
Level for field OE trip relay infinite	OE_Inf	4938.540039
Level for OE trip at OETripSec	OETripLev	5218.080078
Time for field OE trip relay activation	OETripSec	120
Percent of trip level to activate OEL	OELimitLev	70
Percent of trip level to force master xfr	OEXferLev	85
OE Trip Enabled	TripOELTrip	Trip

Over Excitation Limiter (OEL) Straight Time		
Level for straight time protection active	FldCurHiSet	6522.600098
Time required for straight time to activate	FldCurHiSec	1
Level for straight time protection deactivate	FldCurHiRes	5124.899902
Set point for FCR at straight time active	FcrRefHi	5823.75
Set point for FCR at inverse time active	FcrRefLo	4659

Loss of Excitation Settings(LOE)		
LOE1 Trip enable Boolean	TripLOE1Trip	Trip
LOE1 Impedance diameter	LOE1_XD	1
LOE1 Impedance offset	LOE1_XO	0.119999997
LOE1 Delay time	LOE1Sec	0.050000001
LOE2 Trip enable Boolean	TripLOE2Trip	Trip
LOE2 Impedance diameter	LOE2_XD	1.674000025
LOE2 Impedance offset	LOE2_XO	0.119999997
LOE2 Delay time	LOE2Sec	0.5
LOE3 Transfer enable Boolean	XferLOE3Xfer	Transfer
LOE3 Impedance diameter	LOE3_XD	1.914000034
LOE3 Impedance offset	LOE3_XO	0
LOE3 Delay time	LOE3Sec	0.5
LOE4 Transfer enable Boolean	XferLOE4Xfer	Transfer
LOE4 Impedance diameter	LOE4_XD	1.700000048
LOE4 Impedance offset	LOE4_XO	-0.850000024
LOE4 Delay time	LOE4Sec	0.5

Volts/Hertz		
V/Hz level from straight time trip	VHz1TripLev	1.179999948
Time for V/Hz straight time trip	VHz1TripSec	2
V/HZ1 trip enable Boolean	TripVHz1Trip	Trip
V/Hz level for inverse time trip	VHz2TripLev	1.179999948
Time for V/Hz inverse time trip	VHz2TripSec	45
Level for trip relay to pickup at infinite time	VHz2TripInf	1.120000005
Level for trip relay to start accumulation	VHz2TripPU	1.100000024
V/HZ2 trip enable Boolean	TripVHz2Trip	Trip

Power System Stabilizer		
Type (0 = No PSS)	PSS_Type	2
Final Output Gain of Stabilizer	PSSGN	8
Lead time constant of first Lead/Lag block	PSSLD1	0.100000001
Lag time constant of first Lead/Lag block	PSSLG1	0.025
Lead time constant of sec. Lead/Lag block	PSSLD2	0.100000001
Lag time constant of sec. Lead/Lag block	PSSLG2	0.02
Washout Time Constant	PSSWO	5
PSS Inertia	INERTIA	5.532000065
Ramp tracking filter time constant	RTF_TC	0.100000001
Compensation for PSS Slip Calculation	XqSlip	0.269
PSS Output Upper Limit	PSSPLM	0.100000001
PSS Output Lower Limit	PSSNLM	-0.100000001
PSS Enable Power Level	WATTSHI	0.200000003
PSS Disable Power Level	WATTSLO	0.15

F2 Protection Settings

Loss of Excitation Element Settings

Device	Description	Status	Settings
G60: 40-1	40 Loss of Excitation	Trip	Time delay: 0.07, Radius 8.35, Center (R, X) 0 secondary ohms, -10.4 secondary ohms
G60: 40-2	40 Loss of Excitation	Trip	Time delay: 0.5, Radius 13.7, Center (R, X) 0 secondary ohms, -15.8 secondary ohms
EX2100 LOE1	40 Loss of Excitation	Trip	Time delay: 0.05, Diameter 1, Offset -0.12 pu
EX2100 LOE2	40 Loss of Excitation	Trip	Time delay: 0.5, Diameter 1.674, Offset -0.12 pu

V/Hz Element Settings

Device	Description	Status	Settings
EX2100 V/Hz Limiter	24 V/Hz	Limit	Time(sec) , V/Hz(pu): 0.1, 1.09
G60 & T60: 24	24 V/Hz	Trip	Time(sec) , V/Hz(pu): 2, 1.18; 45, 1.1
EX2100 V/Hz Trip, EX2100	24 V/Hz	Trip	VHZ1_TRIP: 1.18, VHZ1_SEC: 2, VHZ2_INF: 1.12, VHZ2_TRIP: 1.18, VHZ2_PU: 1.1, VHZ2_SEC: 45 pu

Voltage Element Settings

Device	Description	Status	Settings
G60: 59-1/2	59 Voltage	Trip	Time(sec) , V(pu): 45, 1.1; 0, 1.5
EX2100 O/V	59 Voltage	Trip	Time(sec) , V(pu): 2, 1.2
G60: 27 Alarm	59 Voltage	Alarm	Time(sec) , V(pu): 60, 0.2

Frequency Element Settings

Device	Description	Status	Settings
G60: 81U	81 Frequency	Trip	Time(sec) , F(Hz): 180, 59.4; 30, 58.4; 7.5, 57.8; 0.75, 57.3; 0.1167, 56.8
G60: 81O	81 Frequency	Alarm	Time(sec) , F(Hz): 0.166, 60.5; 0.017, 61.25

Current Element Settings

Device	Description	Status	Settings
EX2100, EX2100 OE Standard Curves	51ET Current	Limit/Transfe	CurveShape: Transfer, OETripLev: 0, OELimitLev: 0%, OE_Inf: 0, OE_PU: 0, OETripSec: 0, FldCurHiSet: 0, FldCurHiSec: 0, FldCurHiRes: 0, FcrRefLo: 0, FcrRefHi: 0 Adc

APPENDIX G: GLOSSARY

G1 Acronyms

AVR	Automatic Voltage Regulator
CT	Current Transformer
FCR	Field Current Regulator
HIR	High Initial Response
LOE	Loss of Excitation relay (40)
MEL	Minimum Excitation Limiter (also called UEL or URAL in some texts)
MOT	Main Output Transformer
OEL	Over Excitation Limiter
PF	Power Factor (usually used in the context of power factor regulator or controller)
PID	Proportional Integral Derivative
PPT	Power Potential Transformer (used by some vendors to refer to static excitation system power transformer)
PSS	Power System Stabilizer
PT	Potential Transformer
RCC	Reactive Current Compensation
SCL	Stator Current Limiter
UEL	Under Excitation Limiter
V/Hz	Volts-Per-Hertz Limiter
VAR	Reactive Power (usually used in the context of VAR regulator or controller)

G2 Symbols and Variables

The following is a list of common symbols and variables appearing in generator test reports. Where appropriate the normal units of measure have been included in parentheses. If duplicate definitions exist for a symbol, they are listed with an indication of the context.

E_{fg}	generator field voltage (Vdc) (in some references Efd for generator field voltage direct axis)
E_{fe}	main exciter field voltage (Vdc) (in most rotating exciter block diagrams denoted Vr)
E_t	generator ac three-phase terminal voltage (kV)
E_{tref}	terminal voltage reference (kV)
F	generator terminal frequency or compensated frequency (Comp Freq) (Hz)
I	current
I_{fg}	generator field current (Adc)
I_{fe}	main exciter field current (Adc)
I_t	generator ac terminal current (kA)
K_a	AVR gain (pu E_{fd} / pu E_{tref})
K_c	rectifier loading factor (pu)
K_P	proportional gain
K_I	integral gain
K_D	derivative gain
P	active power (in some documents referred to as real power) (MW)
Q	reactive power (in some documents referred to as imaginary power) (MVAr)
R_c	resistive load compensation component
R_{fg}	generator field winding resistance (Ω)
R_{fe}	main exciter field winding resistance (Ω)
R_P	governor permanent droop
R_t	governor temporary droop
S	apparent power (MVA)
T_r	exciter terminal voltage feedback time constant (s)
	governor dashpot reset time (s)
V, E	voltage
V_c	compensated terminal voltage feedback signal (pu E_{tref})
VRMS	generator ac three-phase terminal voltage (kV)
ω	speed (Greek symbol omega) (pu)

X	impedance, per unit
X_c	reactive load compensation component

Exhibit No. TS-023

Laramie River Unit 3

MOD-025 Test Reports and Capability Curves

Kestrel
Power Engineering

MOD 025/026/027 & PRC 019/024/025

NERC Reactive Capability, Exciter/Power System Stabilizer Model Re-Validation and Protection Coordination Report

Laramie River Station Unit 3

K2017_204_R1

Kestrel Power Engineering

Rev.	Date	Submitted by	Comments
0	July 7, 2017	David Parry, P.E.	Initial Draft
1	August 10, 2017	David Parry, P.E.	Correction to PRC 25 analysis. Draft markings removed and final report issued.

Kestrel
Power Engineering

MOD 025/026/027 & PRC 019/024/025

NERC Reactive Capability, Exciter/Power System Stabilizer Model Re-Validation and Protection Coordination Report

Laramie River Station Unit 3

K2017_204_R1

Prepared by: David Parry

Peer Review by: Mike Fogarty, P.E.

EXECUTIVE SUMMARY

This report provides details of the tests and engineering assessment performed on the generator, exciter, governor, power system stabilizer, and protective relaying at Laramie River Station Unit 3 on April 7, 2017.

Models have been provided, suitable for meeting compliance requirements. The following are the main conclusions/recommendations from this report:

1. Reactive capability testing was performed on the unit. Calculated reactive capability and relay and limiter coordination curves and the NERC MOD-025 reactive capability forms are provided as part of this report.
2. The excitation system and power system stabilizer models, figures, and documentation provided in this document address NERC Std. MOD-026-1 requirements.
3. The turbine-governor models, figures, and documentation provided in this document address NERC Std. MOD-027-1 requirements. This unit is not responsive to both over and under frequency excursion events; the unit does not operate in a frequency control mode, except for during normal start-up and shut down. MOD-027-1 R2 will be satisfied per Attachment 1, Row 7 [6] when this is communicated to the Transmission Planner.
4. The excitation system continues to function correctly as commissioned.
5. The power system stabilizer is set to meet regulatory requirements and is in service above 138 MW (0.2 pu).
6. The steam turbine governor does not respond to system frequency deviations. As such, it should be represented by a constant power source.
7. No changes are required to meet NERC Standard PRC-019, PRC-024 requirements.
8. No changes are required to meet NERC Standard PRC-025 requirements.
9. Numerous generator protection elements are duplicated within the excitation system control. Kestrel typically advises against self-protection of the excitation system, such that there are no elements which are duplicated between the excitation system and generator protection. The elements of interest include over-voltage (59), volts per hertz (24) and loss of excitation (40).
10. The nameplate and exciter setting for rated field current do not match. The previous report from the manufacturer lists the exciter setting as rated field current which is different from the nameplate. It is recommended that the nameplate value be corrected. This topic is discussed further in the report.

The exciter, stabilizer, governor and relay settings documented in this report must not be changed without a thorough review and notification of the Transmission Planner.

The Appendices to this report contain details and reference material:

Table of Contents

1 GENERATOR PARAMETERS

Quantities in this report are expressed in per unit or engineering units (e.g. kV, MVA). Values expressed in per-unit are divided by a base value such that they will normally range between 0 and 1 for normal operating conditions. The per unit base data summarized in Table A2 correspond to the values used in reporting the generator impedances and time constants.

A list of generator parameters was supplied in reference [11], and these were used as the starting point for modeling this generator. Appendix A3 summarizes the recommended simulation model and parameters. Confirmation of key generator parameters was made by test as listed below.

1.1 Open Circuit Saturation Curve

Figure B1 displays the open-circuit saturation curve, along with the tangent to the lower measurements, forming the air-gap line. The measurements shown in the figure are from the previous testing report [11]. Saturation curve measurements were not repeated; however, the steady state measurements (Figure C2) and step response (Figure C1) indicate that the saturation characteristic is still similar to the previously measured. The base field current is determined by the intersection of the air-gap line and rated terminal voltage (i.e. 1 pu). The field resistance corresponding to a temperature of 100°C was used to determine the base field voltage listed in Table A2.

The saturation coefficients S(1.0) and S(1.2) in Table A3 describe the saturation curve of Figure B1 using the quadratic saturation curve of the GENROU model.

1.2 Time Constants and Transient Reactances

The d- and q-axes parameters were verified as part of the previous testing [11]. The values have been used without change and confirmed by a simulation of the on line step response, such as the one shown in Figure C1. The simulations include the effects of temperature on the rotor resistance and field voltage.

1.3 Combined Turbo-Generator Inertia

A partial load rejection test was performed during previous testing [11] to confirm the value of inertia (H) 2.77 MW-s/MVA. The value has been used without change.

1.4 Synchronous Reactances

Generator synchronous reactances were confirmed from static measurements of field current, terminal voltage, active and reactive power. The field current calculated using the recommended synchronous reactance values and generator saturation parameters are compared with the measured values in Table C2.

1.5 Generator Capability Curve

Calculated capability and coordination curves are shown in Figure B3. The curves have been provided for the purpose of satisfying a portion of NERC PRC-019 requirement to show the coordination of the excitation limiters with protective relays and unit ratings; they are not intended to supersede the utility’s official curves. The capability curves have been calculated based on the measured results and verified generator impedance and saturation data. The limit for lagging power factor conditions is a function of the exciter setting for the field current rating listed in Table A2. It must be remembered that this limit is highly

dependent on terminal voltage, and therefore field current, not reactive power, should be monitored during extended over-excited operation.

The limits shown in the leading power factor region are the exciter under excitation limiter (UEL) curve, generator core-end heating limit and loss of excitation (LOE) relay characteristics. Excitation limiters and relay coordination are discussed elsewhere in the report.

In the leading power factor region, no attempt was made to identify the steady state stability boundary. The conventional assumptions used to calculate the steady state stability limit, as shown in the coordination example NERC Std. PRC-019-2 [7], are based on operation with fixed field voltage. This does not apply to this unit, as it is equipped with a continuously-acting automatic voltage regulator and power system stabilizer.

The manufacturer's capability curve is provided for reference in Figure B2

Additional information regarding the coordination between excitation limiters, generator protection, and equipment capability is provided in Section 5.

2 EXCITATION SYSTEM

This unit is equipped with a GE EX2100 full static excitation system fed from the generator terminals.

2.1 Power Stage

The power stage consists of 6-pulse thyristor bridges supplied by an excitation transformer with ratings summarized in Table A2.

The theoretical no-load ceiling voltage is calculated from the transformer secondary voltage:

$$\begin{aligned} E_{d0} &= 1.35 * V_{SEC} \\ &= 1.35 * 1090 \text{ Vac} \\ &= 1472 \text{ Vdc } = 8.15 \text{ pu} \end{aligned}$$

The no-load ceiling voltages are established by the bridge advance and retard firing limits:

$$\begin{aligned} V_{RMAX} &= E_{d0} * \cos(\alpha_{min}) = 1.00 * E_{d0} \\ &= 1472 \text{ Vdc} = 8.15 \text{ pu} \end{aligned}$$

$$\begin{aligned} V_{RMIN} &= E_{d0} * \cos(\alpha_{max}) = -0.80 * E_{d0} \\ &= -1177 \text{ Vdc} = -6.52 \text{ pu} \end{aligned}$$

These ceiling voltages are entered as a fraction of the no-load ceiling E_{do} in the ST4B model (Appendix A4).

The effect of exciter transformer impedance on exciter output voltage is represented by the commutating impedance, K_C.

2.2 Automatic Voltage Regulator

Control is provided by a GE EX2100 digital voltage regulator which also implements the limiter and power system stabilizer functions. The EX2100 digital control implements a proportional-integral (PI) transfer

function based on terminal voltage feedback. The appropriate simulation model is the IEEE type ST4B [1] shown in Appendix A4.

The AVR proportional and integral gains, K_{PR} and K_{RI} respectively, are set via the EX2100 software.

The terminal voltage measurement time constant, T_r, and the exciter time constant, T_a, are approximations of the device delays and filters. The model values selected provide a good representation of the closed-loop voltage regulator response using the available simulation model. The model values used in the simulation program are limited by the program used and the simulation time step of the study as noted in Appendix A4.

The measured closed-loop AVR step-response, with the unit operating online is shown in Figure C1. The simulated response using the AVR gains and time constant parameters listed in Appendix A4 closely matches the measured result.

2.3 Reactive Current Compensation

This unit is connected to the bulk power system through a dedicated step-up transformer. In this case, reactive current compensation (RCC) is typically not used, and the parameter has been set to 0.

The absence of reactive compensation was confirmed by applying identical AVR reference step changes with the unit off line and on line as shown in Figure C3 and Figure C1. The magnitude of the step test signal was calibrated during the open circuit tests.

2.4 Under Excitation Limiter

The UEL was set by the manufacturer to operate at levels tabulated in Appendix F and shown with the capability curves (Figures B3). The settings match the core end heating curve and an offset is then used to provide a margin between the UEL and core end heating curve.

The UEL was not tested dynamically.

2.5 Over Flux Limiter

The unit is equipped with a V/Hz limiter function within the exciter control. The as-commissioned V/Hz limit setting is 106% Et/% frequency and acts to prevent over fluxing of the machine. Coordination with V/Hz relays is discussed in Section 5.

2.6 Pf/Var Controls

This unit is equipped with both power factor (pf) and reactive power set point (VAR) controllers. NERC VAR-002 prohibits the use of pf/Var set point controllers on units connected to the bulk power system, so they were left turned off.

2.7 Over Excitation Limiter

The OEL implements both an inverse-time and fixed-time characteristic. The manufacturer's inverse OEL settings are 102% trip pick-up and an alarm pickup of 70% of the trip level, 112% rated field current for 120 seconds. The fixed-time OEL triggers at 140% rated field current after 1 second(s), and limits field current to 125% of rated until the inverse time OEL triggers. The OEL then limits to 100% of rated field current with compensation for temperature. The OEL settings are based on the rated field current setting

shown in Appendix F. The rated current setting (4659 Adc) does not match the unit nameplate value of 4692 Adc. The previous report [11] notes that the nameplate is 4692 Adc; however, following the field rewind in 2011 the new value is 4659 Adc. The report does not provide additional details on why the field current rating would decrease. The nameplate should be corrected to reflect the new rating and to prevent further confusion when using the nameplate to determine the equipment capability. Both curves are shown in the capability curve in Figures B3, but the value of 4659 Adc is used in the EX2100 digital settings and therefore the OEL settings are based on this value.

The OEL was not tested dynamically.

3 POWER SYSTEM STABILIZER

The GE EX2100 digital excitation system includes a power system stabilizer that provides supplementary damping. The stabilizer implements an IEEE standard type PSS2A transfer function [1] shown in Appendix A5. The stabilizer settings are tabulated in Appendix F.

It should be noted that the EX2100 software is configured as the PSS2B option. The software does not employ the third lead/lag stage of the PSS2B structure, but does make use of the optional biquadratic filters. The biquadratic filters are typically used to reduce the interaction of the PSS with torsional modes of the turbine. These notch filters are set with center frequencies above 10 Hz that are usually outside the normal range of frequencies that can be properly simulated in power system studies. It should be noted that the turbine model is also a single-mass equivalent model and thus no torsional frequencies are represented for this unit. As such, the effect of these torsional filters in the PSS can be neglected in the dynamic simulation model and thus the PSS can be represented as a PSS2A structure.

3.1 Stabilizer Inputs

This stabilizer uses two measured inputs, electrical power and compensated frequency, and is the presently accepted industry standard throughout North America. Both inputs are derived from the generator PT and CT secondary signals. The first input is the compensated frequency calculated based on the parameter $X_{q\ COMP}$ shown in Table A5. The available simulation models do not have the option to use compensated frequency as an input to the PSS model, so speed deviation is used instead.

The compensation setting, *Xq for slip calc*, was selected by the manufacturer during initial commissioning of the PSS.

3.2 Stabilizer Tuning

The PSS settings were selected by the manufacturer during initial commissioning of the PSS. The calculated terminal voltage versus AVR reference frequency response (inverted) along with the manufacturer-selected PSS phase compensation is shown in Figure B4. The difference between the selection and requirement is within the accepted ±30° bound [12] required by WECC [13] over the range 0.1 Hz to 1.0 Hz.

Improvements to inter-area mode damping (frequencies below 0.7 Hz) cannot be assessed through local tests. Simulations representing a large portion of the interconnected power system are required to assess the effectiveness of a given PSS implementation on these modes. No changes to the selected parameters are recommended without detailed study.

The selected parameters provide damping of the unit's local mode of oscillation, as shown in Figure C1 with the PSS on at its as-left gain.

3.3 Output Limits and Control

The PSS output limits were set to +/- 10% terminal voltage reference during initial commissioning of the PSS.

The PSS is selected to automatically turn on above the minimum load (0.2 pu), and turn off at a slightly lower level (0.15 pu) to provide hysteresis. This hysteresis is required to prevent multiple on/off operations during turbine output changes near the turn-on level.

This stabilizer design includes a "ramp tracking" filter to minimize terminal voltage and reactive power changes during normal loading and unloading.

4 TURBINE GOVERNOR

The coal-fired steam turbine for this unit is connected directly to the generator rotor, which operates at 3600 rpm. The governor employed is an Emerson Ovation digital controller.

The unit is not responsive to both over and under frequency excursion events; the unit operates on valve position control and does not receive influence from system frequency deviations. This has been confirmed by review of the control system logic.

As such, the unit should be modeled as having a fixed mechanical power source for typical dynamic simulation studies. The representation of a constant mechanical power from the turbine is usually automatically assumed when no explicit turbine/speed governor model is provided. Thus, the fact that no explicit model has been provided implies that these units will be represented as fixed mechanical power sources and, as such, the requirements from NERC Std. MOD-027 are met.

5 LIMITER AND PROTECTION COORDINATION

5.1 Introduction

NERC standards PRC-019-2 [7] and PRC-024-2 [8] have been instated to ensure coordination of generating units' protective relay settings with voltage regulator controls, limit functions, equipment capabilities, and NERC voltage/frequency ride-through requirements. Review of relevant protective relay settings has been performed to confirm proper coordination in accordance with NERC standards, and with reference to the IEEE Guide for AC Generator Protection [3].

Laramie River Station Unit 3 is equipped with hardware as shown in Table A1. The following sub-sections summarize the relevant settings and their relation to the NERC standards and industry standard practice. Base values (voltage, current and impedance) are listed in Table A2.

The excitation system is duplicating protection for which there are dedicated primary and backup generator protective devices (G60). The duplicated protective elements include the following: volts per hertz, over-voltage and loss of excitation. Kestrel typically advises against self-protection of the excitation system, such that there are no elements which are duplicated between the excitation system and generator protection unless extenuating circumstances have been identified. The excitation system over-voltage trip does not coordinate with the generator protection. The excitation system manufacturer typically enables all of the

available device protection by default and, unless previously reviewed, it may not be apparent to the Basin relay staff that protection exists in the excitation system. It is likely that this is the case for this equipment and coordination between the excitation and generator protective elements is not adequate. Protective devices are typically subject to stringent review and routine calibration and it is likely that the excitation system protection elements have not been subjected to the same attention that the generator protective devices have. Use of duplicate protection in the excitation system and its coordination with the generator protection devices should be reviewed. If any changes are made to the device settings, this report should be updated to reflect the changes.

5.1.1 PRC-019 Coordination Requirements

NERC Standard PRC-019-2 [7] requires the following:

> R1.1.1 - The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnection the generator unnecessarily.
>
> R1.1.2 - The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to **limit the extent of damage** when operating conditions exceed equipment capabilities or stability limits.

Thus, it is conceivable that some protection elements are set beyond the equipment capability and, thus, the unit would operate for a certain period of time beyond its capability or stability limit. As long as the risk of damage is considered acceptable by the equipment owner, the requirement from PRC-019-2 is met.

5.1.2 PRC-019 and Coordination with Steady State Stability Limit

The steady state stability limit in the leading power factor region was not included in the coordination assessment. The conventional assumptions used to calculate the steady state stability limit, as shown in the coordination example NERC Std. PRC-019-2 [7], are based on operation with fixed field voltage. This does not apply to this unit, as it is equipped with a continuously-acting automatic voltage regulator.

Per NERC Std. VAR-002-4 [10], the unit should be operated in the automatic voltage control mode (AVR in service and controlling voltage) in most cases (excluding start-up, shutdown or testing). Operation in any other mode, including manual control, would require a justification as part of the notification process to the Transmission Operator.

Operation in AVR mode significantly affects the steady state stability limit [14], moving the stability limit much beyond the capability of the generator and usually beyond the curves associated with the loss-of-excitation relays.

On the other hand, the under-excitation limiter (UEL) and other elements of the excitation control are an integral part of the operation on automatic voltage control. The UEL curve shown in Figure B3 is specific to the operation on automatic voltage control. Thus, including the steady state stability limit associated with operation in manual control and the UEL characteristic on the same coordination figure would be inconsistent.

Operation on manual control implies operation in a less stable mode than on automatic voltage control. It typically also implies that the excitation system will not provide the limiting function (UEL), so the loss of excitation relay or the steady state stability limit might be reached during under-excited operation on manual control. In either case, it will result in the trip of the generation unit. As long as the protection settings are

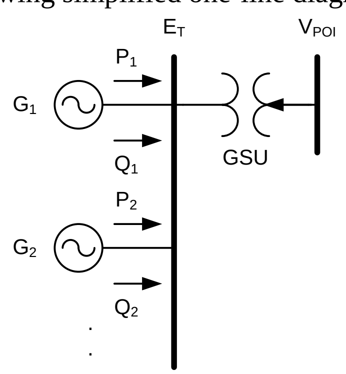
limiting the risk of damage to the equipment, PRC-019 does not require the protection settings to prevent operation beyond the stability limit (R1.1.2).

5.1.3 PRC-024 Voltage Requirements

The Voltage Ride-Through Time Duration Curve in Attachment 2 of PRC-024-2 [8] specifically provides voltages at the point of interconnection (POI) to the Bulk Electric System (BES), which is the high-voltage side (HV) of the generator step-up transformer (GSU) for conventional generation units. On the other hand, the protective relays on conventional generation units are typically connected to PTs and CTs at the terminals of the machine, the low-voltage (LV) bus where the GSU is connected. Thus, the voltage ride-through time duration curves have been translated to the generator terminals to simplify the comparison of generator and GSU protection settings to the PRC-024 requirements. The generator terminal voltage is calculated considering the voltage at the POI given in voltage ride-through curves provided in PRC-024 and also considering the following loading conditions, believed to be the most probable for the generator unit, in accordance with Attachment 2 of PRC-024, particularly the section regarding evaluation of protective relay settings:

a) All units connected to the same transformer are online and operating.
b) All the units are dispatched at maximum power output, per the available information for these units. The maximum power output of each unit will be determined by their respective maximum turbine rated output or the maximum continuous rating (MCR) or will be calculated from the generator MVA and rated power factor.
c) For under-voltage conditions at the POI, all units will be dispatched at their rated power factor, corresponding to a maximum reactive power output. For over-voltage conditions at the POI, all units will be dispatched at 0.95 power factor (under-excited condition), resulting in reactive power absorption.
d) The excitation system is in AVR control mode considering a voltage reference setpoint within the usual operating range of the unit(s), in accordance with NERC Std. VAR-002 [10].

Based on these assumptions, the voltage-ride through time duration curve in PRC-024-2 will be reflected to the terminal bus of the generator(s) (LV bus of the GSU transformer). For each GSU in the plant, the calculations will be based on the following simplified one-line diagram:



Since these synchronous generators are operated on AVR control, the generator terminal voltage E_T is held constant or follows the reactive current compensation (RCC) setting (if applicable) independently of the voltage at the POI, until the reactive capability is reached, as shown in the figure below. Therefore, the generator terminal voltage will only deviate significantly from the AVR voltage reference setpoint once the reactive capability of the generation units is reached. In the assumptions above, the reactive capability of the unit is represented in a simplified manner, considering the rated power factor of the unit for over-excited operation (Q_{MAX}) and 0.95 power factor for under-excited operation (Q_{MIN}). It should be noted that these

assumptions are similar to the current practice for representation of synchronous generators in power flow studies and other similar steady state calculations.

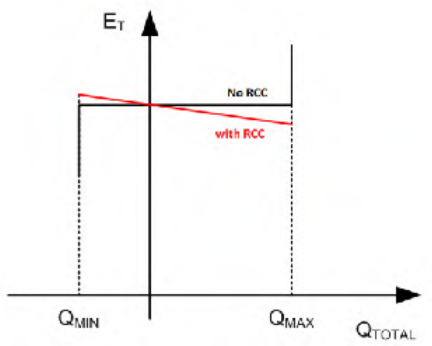


Figure D1 presents the calculated voltage ride-through time duration curve as seen from the generator terminal bus (LV bus of the GSU). The calculation of the voltage at the generator terminal bus is based on the assumptions listed above, the POI voltages given in PRC-024-2, and the GSU data shown in Appendix A2.

5.4 Under-Voltage Elements (27)

Generators built per the ANSI/IEEE C50.13 standard [2] for round rotor synchronous generators are designed for continuous online operation down to 95% of rated voltage. This includes continuous operation within the manufacturer provided generator capability curves (shown in Figure B2) down to 95% rated voltage. As such, some machines include under voltage limiter and/or protective devices.

The IEEE Guide [3] prescribes the under-voltage elements as an interlock for other protective devices, rarely to be applied as a standalone trip function.

The excitation system is not equipped with under-voltage limiter or protective functions.

The generator (G60) or GSU (T60) protection do not make use of under-voltage protective functions for standalone trips. Settings are documented in Appendix F2. The G60 and T60 devices use an under-voltage element as part of de-energized bus logic. As it is not part of a trip for normal operation it was not included in the coordination study.

The protective relays' under-voltage settings meet NERC PRC-019 and PRC-024 requirements, as shown in Figure D1. No changes are required.

5.5 Over-Voltage Elements (59)

As with under-voltage, generators built per the ANSI/IEEE C50.13 standard [2] are designed for continuous online operation within the manufacturer provided generator capability curves up to 105% of rated voltage. As such, some machines include over voltage limiter and/or protective devices.

The IEEE Guide [3] recommends two stages of tripping for over-voltage conditions, generally as applied to hydro generators. The first stage is normally an instantaneous unit set to pick up at 130% to 150% of the nominal generator voltage. The second stage is an inverse-time element with pickup of approximately 110% nominal voltage. As described in the IEEE Guide [3], the over-voltage function may be configured to alarm

only for steam and gas turbine generators, due to the rapid response of the speed-control systems and voltage regulators.

The excitation system is equipped with an over-voltage protective function. The device initiates an excitation trip with a pickup (*VHiTripLev*) and delay (*VHiTripSec*) documented in the settings in Appendix F1. The excitation system is duplicating the generator over-voltage protection (G60). As discussed above, duplication of generator protection elements within the excitation system is typically not recommended. Use of duplicate over-voltage protection in the excitation system and its coordination with the generator protection devices should be reviewed. If any changes are made to the device settings this report should be updated to reflect the changes.

The generator protection relay's over-voltage elements are set to trip with definite time settings. Over-voltage relay settings are shown in Appendix F2.

The protective relays' over-voltage settings meet NERC PRC-019 and PRC-024 requirements, as shown in Figure D1. No changes are required.

5.6 Volts/Hertz Elements (24)

The IEEE Guide [3] suggests either a single relay or double relay scheme for V/Hz protection. Recommended settings for a single, definite time relay are a pickup of 110% and delay of 6 seconds. The two-relay scheme includes a quick trip relay with pick up between 118% and 120% V/Hz and timer to trip set between 2 and 6 seconds. The second relay is set at 110% V/Hz and is to trip just below the manufacturer's recommended generator and/or transformer operating time at 110% V/Hz; the delay is typically between 45 and 60 seconds. Alternatively, a single inverse time relay can be used to closely match the generator or transformer V/Hz characteristic, whichever is more restrictive.

The excitation system includes a V/Hz limiter function as documented in Section 2.5 with a definite time characteristic. The transfer and protection functions operate with a composite characteristic as shown in the Figure D2. As discuss above, the excitation is duplicating the external generator protective device's volts per hertz protection and the settings do not appear to have been chosen to coordinate with the dedicated protective devices. The use of the excitation system V/Hz protection trip should be reviewed and any changes to the settings be reflected in this report.

The generator protection relay's V/Hz elements are set to trip with definite time characteristics. The implementation matches the IEEE recommendation. V/Hz relay settings are shown in Appendix F2.

Generator and generator step-up transformer manufacturers' over-fluxing capability curves are not available; thus, the coordination of the equipment capabilities cannot be assessed against limiter and protection settings. Industry standards do not at present specify definite short time capabilities for generators and transformers and the equipment manufacturers should provide overexcitation capability limits [3]. In the absence of actual OEM V/Hz capability information, the IEEE Guide [3] typical tripping recommendation of 118% setpoint with a delay between 2 and 6 seconds has been assumed as adequate to limit the extent of damage due to excessive overexcitation in this coordination study. It is recommended that Basin protection review this assumption and provide feedback if it feels this is not an accurate assumption. If the manufacturer curves become available, the coordination study should be updated accordingly.

Coordination of the V/Hz elements is shown in Figure D2. Coordination of the V/Hz elements, under- and over-voltage elements, and NERC PRC-024 requirements are shown in Figure D1. The V/Hz elements are properly coordinated and no changes are required to meet PRC-019 and PRC-024 requirements.

5.7 Loss of Excitation Elements (40)

The IEEE Guide [3] approach to loss of excitation protection employs two offset mho elements with both offset from the impedance plane by one-half the generator transient reactance $-X'_d/2$. The delayed element is set with a diameter equal to the d-axis synchronous reactance, X_d, with a delay between 0.5 and 0.6 seconds. The IEEE Guide [3] recommends that a transient stability study be performed to determine the appropriate unit specific time delay for this element. The instantaneous element is set with a diameter of 1 pu. Base impedance is listed in Table A2.

The excitation system is equipped with limiting, transfer and protective functions in the leading power factor region. The UEL operates as described in Section 2.4. The excitation transfer and protective elements operate using a diameter and offset characteristic with settings shown in Appendix F1. As discuss above, the excitation system is duplicating protective functions for which there is dedicated external primary and backup protection. Use of the excitation system protection elements should be reviewed and any changes to the device settings should be updated in this report.

The generator protection loss of field elements match the IEEE recommended approach. Settings are shown in Appendix F2.

Coordination of the loss of field elements with the unit's core end heating curve, under-excitation limiter (UEL), and 0.95 power factor are shown in the P-Q plane in Figure B3 and the R-X plan in Figure D3. No changes are required to meet PRC-019 requirements.

5.9 Frequency Elements (81)

The IEEE Guide [3] recommends coordination of frequency elements with the turbine manufacturer's permissible frequency-band operating time guidelines. The NERC PRC-024 standard has regional specific frequency ride-through requirements.

The excitation system has no frequency specific protective devices.

The generator protection utilizes under-frequency protection and over-frequency alarm elements. Five of the six available definite time under-frequency elements are being used for protection and two of the available four over-frequency elements are being used for alarm indication. Settings are documented in Appendix F3.

The protective devices cannot be assessed against equipment capability, as the manufacturer's permissible frequency duration curves for the turbine are not available. If the curves become available, the coordination study should be updated accordingly.

Coordination of the relay frequency elements with NERC PRC-024 requirements is shown in Figure D4. The under-frequency relay settings match with the NERC Western region abnormal frequency ride-through requirements. Since the over-frequency settings are for alarm indication, no settings review is required, although it is worth noting that the alarm levels do not match the NERC Western region curve. No changes are necessary to meet PRC-024 under-frequency ride through requirements.

5.10 Field Thermal Protection

The IEEE Guide [3] recommends an inverse time relaying scheme in accordance with ANSI standards for short-time thermal capabilities for cylindrical rotor machines [2], with 5% to 10% margin between the relay characteristic and the field capability curve.

The excitation system provides both limiting, transfer and protective functions for field thermal protection. The limiting function works as described in Section 2.7. The transfer and protective elements function using an inverse time curve described by the settings documented in Appendix F1. As discussed previously, the settings in the excitation system are provided in percent of rated field current using the excitation system parameter of 4659 Adc (*AFFL*), which differs from the nameplate value of 4692 Adc. The curves shown in Figure D5 are provided in PU on the nameplate value base. Therefore, the pickups will not directly match the settings.

No documentation for discrete field thermal protection device was provided. If such a device exists, the settings should be provided and this report updated to include those settings. Field thermal protection may exist in the form of an over current on either the high or low side of the excitation PPT.

Coordination of the excitations system's limiting and protective functions, field overcurrent relay, and the ANSI curve for short time thermal capability is shown in Figure D5. Coordination of the excitation system functions in steady state, rated field current, and rated power factor is shown in the capability curves of Figure B3. No changes are required.

5.11 Stator Thermal Protection

The IEEE Guide [3] recommends an inverse time relaying scheme in accordance with ANSI standards for short-time thermal capabilities for cylindrical rotor machines [2], with margin between the relay characteristic and the capability curve. The settings are to be chosen such that the scheme will not trip below 115% full load current yet provides tripping in a prescribed time for overloads above 115% of full load current. A recommended coordination for the tripping scheme is 7.0 seconds at 226% full load current.

The excitation system provides no enabled functions for stator thermal protection.

The generator protection over-current element is only used for breaker failure detection and its coordination was not considered in this review.

No changes are required.

6 GENERATOR RELAY LOADABILITY ASSESSMENT

NERC Standard PRC-025 [9] has been instated to prevent unnecessary tripping of generators during system disturbances for conditions that do not pose a risk of damage to the associated equipment. The scope of this standard includes load-sensitive protection relaying on all devices which support the transfer of energy between the generator and the Bulk Electric System (BES). This includes the generating unit(s), generator step-up (GSU) transformer(s), any unit auxiliary transformer(s) (UAT) that supplies overall auxiliary power necessary to keep the generating unit(s) online, and equipment connecting the GSU transformer(s) to the transmission system that is used exclusively to export energy to the BES. Review of relevant protective relay settings has been performed to confirm proper coordination with the requirements prescribed in the NERC Standard.

The ratings of the equipment within the scope of this study are listed in Table A1. These ratings were used in the calculations presented by the NERC standard to determine the maximum allowable impedance reach

for phase distance relay (21) elements and the minimum allowable pickup current for phase overcurrent relay (50/51/67) elements.

6.1 Generator Loadability

NERC Standard PRC-025 [9] provides requirements for phase distance relay (21) elements that are applied to synchronous generating units are directed towards the Transmission System as well as phase time overcurrent relay (51) or voltage-restrained phase time overcurrent relay (51V-R) elements that are applied to synchronous generating units.

The generator protection (G60) is configured with three phase distance relay (21) elements. The first two elements are of interest to PRC-025 review because they look out past the generator, while the third element is set with a reverse reach and is not applicable to the standard. The settings for the scheme meet the requirements of NERC Standard PRC-025, as shown in calculations of Appendix D6. No changes are required.

6.2 GSU Transformer Loadability

NERC Standard PRC-025 [14] provides requirements for phase distance relay (21) elements that are applied to either side of the GSU transformer and directed towards the Transmission System, phase time overcurrent relay (51) elements that are applied to either side of the GSU transformer, and phase directional time overcurrent relay (67) elements that are applied to either side of the GSU transformers and directed towards the Transmission System. There are also requirements for supervisory phase overcurrent relay (50) elements that are applied to the high-voltage side of the GSU transformer as well as for supervisory phase directional overcurrent relay (67) elements that are applied to the high-voltage side of the GSU transformer and directed towards the Transmission System. The supervisory relay elements must be associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications.

The GSU transformer protection (T60) is not enabled with relay elements of interest to NERC Standard PRC-025. No changes are required.

6.3 Unit Auxiliary Transformer Loadability

NERC Standard PRC-025 [14] provides requirements for phase time overcurrent relay (51) elements applied at the high-voltage side terminals of UAT(s) that are critical to operation once the unit(s) are released to dispatch, operating under normal conditions. Only relays that cause the associated generator(s) to trip due to generator lockout or direct trip of the generator main breaker are within the scope of this study. Relays protecting start-up, standby, and reserve UATs are not subject to NERC Standard PRC-025 requirements.

Excitation transformer protective relay elements are not part of the scope of NERC Standard PRC-025.

The UATs are not equipped with relay elements of interest to NERC Standard PRC-025. No changes are required.

6.4 Switchyard Equipment Loadability

NERC Standard PRC-025 [14] provides requirements for phase distance relay (21) elements that are applied to equipment connecting the GSU transformer(s) to the Transmission System and directed towards the

Transmission System, phase time overcurrent relay (51) elements that are applied to equipment connecting the GSU transformer(s) to the Transmission System, and phase directional time overcurrent relay (67) elements that are applied to equipment connecting the GSU transformer(s) to the Transmission System and directed towards the Transmission System. There are also requirements for supervisory phase overcurrent relay (50) elements that are applied to equipment connecting the GSU transformer(s) to the Transmission System as well as for supervisory phase directional overcurrent relay (67) elements that are applied to equipment connecting the GSU transformer(s) to the Transmission System and directed towards the Transmission System. The supervisory relay elements must be associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications.

The connection of the unit to the bulk electric system is through a network configuration and not through single or multiple radial lines. As such, the line protection (L60) is not within the scope of the NERC Standard PRC-25 requirements.

No changes are necessary to meet NERC Standard PRC-025 requirements.

7 REFERENCES

1. *IEEE Recommended Practice for Excitation System Models for Power System Stability Studies*, IEEE Std 421.5.

2. *Requirements for Cylindrical-Rotor 50 and 60 Hz Synchronous Generators Rated 10 MVA and Above*, ANSI/IEEE Std. C50.13.

3. *IEEE Guide for AC Generator Protection*, IEEE Standard C37.102.

4. *Verification of Generator Gross and Net Reactive Power Capability*, NERC Standard MOD-025-2.

5. *Verifications of Models and Data for Generator Excitation System Functions*, NERC Standard MOD-026-1.

6. *Verification of Models and Data for Turbine/Generator Speed/Load Control Functions*, NERC Standard MOD-027-1.

7. *Coordination of Generator Voltage Regulator Controls with Unit Capabilities and Protection*, NERC Standard PRC-019-2, Version 2.

8. *Generator Protective System Performance During Frequency and Voltage Excursions*, NERC Standard PRC-024-2.

9. *Generator Relay Loadability*, NERC Standard PRC-025-1.

10. *Generator Operation for Maintaining Network Voltage Schedules*, NERC Standard VAR-002-4.

11. *Basin Electric Power Cooperative (BEPC), Laramie River Station (LRS) Unit 3 Machine Test & Model Derivation*, GE Energy, Sept 6, 2011. PDF provided by Basin personnel.

12. *IEEE Tutorial Course Power System Stabilization Via Excitation Control*, Presented at the IEEE Power Engineering Society General Meeting, Tampa Florida, 28th June 2007.

13. *Power system Stabilizer Design and Performance*, VAR-502-WECC-0, April 2004.

14. C. Concordia, *Steady-State Stability of Synchronous Machines as Affected by Voltage-Regulator Characteristics*, Transactions of the AIEE, vol. 63, no. 5, pp. 215-220, May 1944 http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=5058926&isnumber=5058924

APPENDIX A: MODELS/RATING NAMEPLATES

A1 Ratings

A2.1 Generator

Description	Parameter	Value	Units
Generator Base MVA	MBASE	690	MVA
Generator Stator Base Voltage	Etbase	24	kV
Generator Stator Base Current	Itbase	16.6	kA
Generator Rated Speed	rpm	3600	rpm
Rated Power Factor	pf	0.9	
Rated Field Current (rated MVA and pf)	IfgRated	4692	Adc
Rated Field Voltage (rated MVA and pf)	EfgRated	500	Vdc
Calculated No-Load Field Current	Ifgnlcalc	2025	Adc
Generator Base Field Current	IfgBase	1771	Adc
Generator Base Field Voltage	EfgBase	189	Vdc
Generator Base Field Resistance	RfgBase	0.106	Ω
Generator Base Field Temperature	TfgBase	100	°C
Generator Stator Base Impedance	Zbase	0.835	Ω

A2.2 Excitation Power Supply

Description	Parameter	Value	Units
Apparent Power of PPT	kVA	8061	kVA
Primary Voltage	kV HV	24	kV
Secondary Voltage	kV LV	1090	Vac
Impedance	Z	6.3	%
Number of phases	Phases	3	
Frequency	Freq	60	Hz

A2.3 Generator Step-up Transformer

Description	Parameter	Value	Units
LV Rated Voltage	GSU_LV_Rated	23.4	kV
HV Rated Voltage	GSU_HV_Rated	345	kV
Rated MVA 1	ONAN	630	MVA
Rated MVA 2	ONAF1	706	MVA
GSU Resistance	GSU_R	0	%
GSU Reactance	GSU_X	8.1	%
Tap Position	GSU_Tap	100	%
Base for Impedance	GSU_MVA	630	MVA
Winding Connection	LV:Delta-HV:Grounded-Y		

System HV Nominal Voltage	E_sys	345	kV

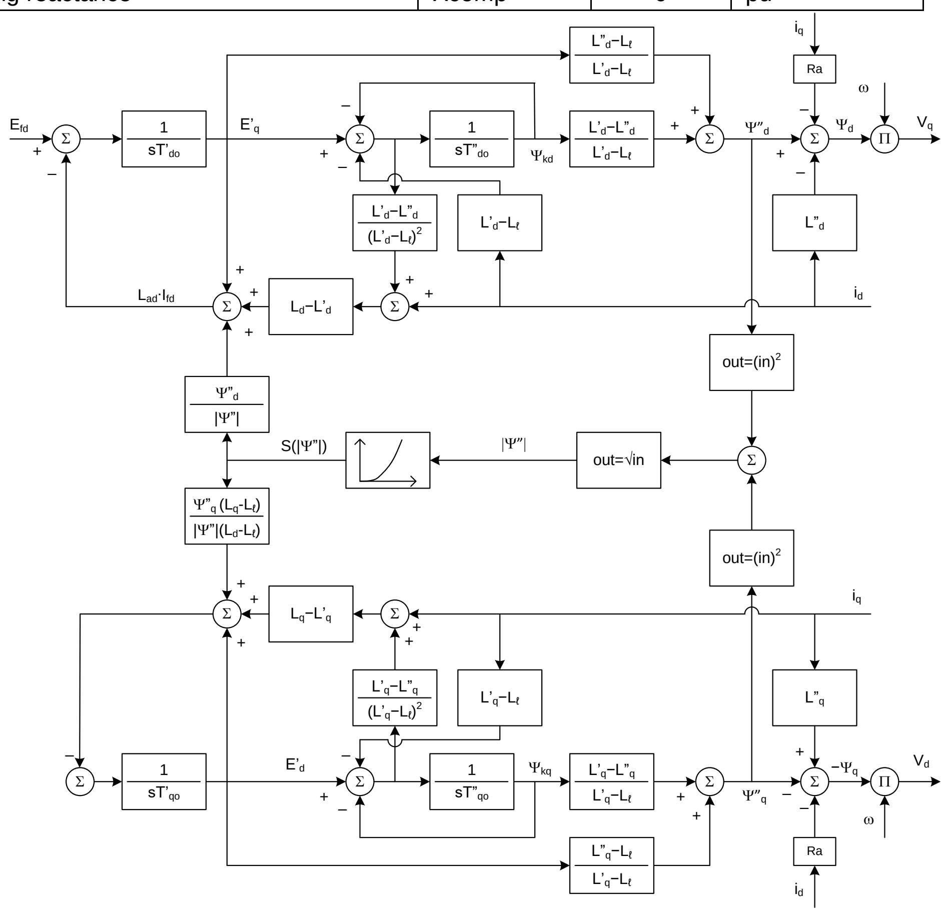
Notes:

1. The system nominal voltage is not part of the GSU rating, but is necessary information for protection coordination calculations

A2 Generator Model

Generator Model GENROU: Round Rotor Generator Model
PSLF Model

Description	Parameter	Value	Units
d-axis OC transient time constant	T'do (>0)	4	s
d-axis OC sub-transient time constant	T"do (>0)	0.035	s
q-axis OC transient time constant	T'qo (>0)	0.495	s
q-axis OC sub-transient time constant	T"qo (>0)	0.067	s
Inertia	H	2.766	MW.s/MVA
Damping	D	0	pu
d-axis synchronous reactance	Xd	1.68	pu
q-axis synchronous reactance	Xq	1.564	pu
d-axis transient reactance	X'd	0.289	pu
q-axis transient reactance	X'q	0.464	pu
subtransient reactance	X"d=X"q	0.235	pu
leakage reactance	Xl	0.228	pu
saturation factor at 1.0 pu Et	S(1.0)	0.143	pu
saturation factor at 1.2 pu Et	S(1.2)	0.336	pu
stator resistance	Ra	0.0032	pu
compounding resistance	Rcomp	0	pu
compounding reactance	Xcomp	0	pu



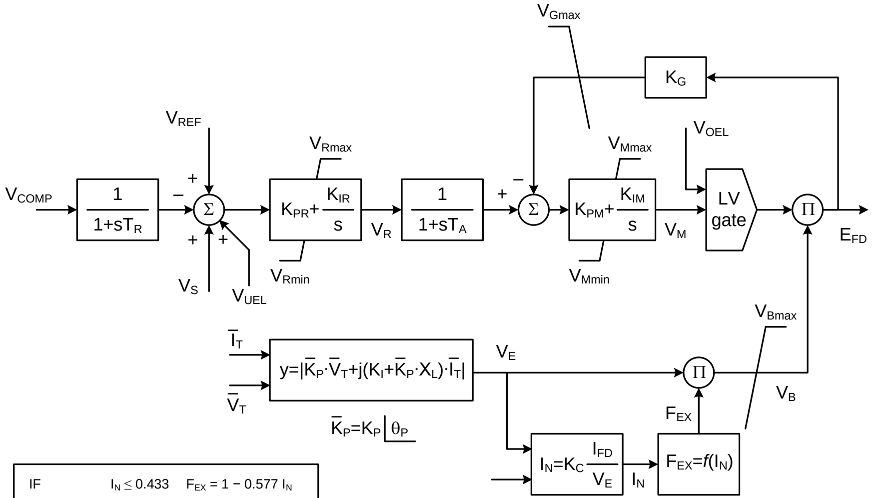
A4 Excitation System Model

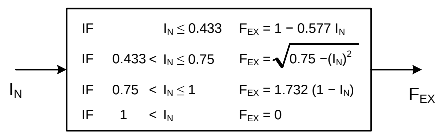
Excitation Model IEEE 421.5 Std. ST4B
PSLF Model ESST4B

Description	Parameter	Value	Units
voltage transducer time constant	Tr	0	s
AVR proportional gain	Kpr	5.85	pu
AVR integral gain	Kir	5.85	pu
AVR time constant	Ta	0.01	s
AVR maximum output	Vrmax	1.00	pu
AVR minimum output	Vrmin	-0.80	pu
inner loop proportional gain	Kpm	1	pu
inner loop integral gain	Kim	0	pu
inner loop regulator maximum output	Vmmax	1.00	pu
inner loop regulator minimum output	Vmmin	-0.80	pu
inner loop feedback gain	Kg	0	pu
potential source gain	Kp	7.80	pu
phase angle of potential source	Angp	0	degrees
current source gain	Ki	0	pu
rectifier regulation factor	Kc	0.14	pu
leakage reactance	Xl	0	pu
maximum excitation voltage	Vbmax	9.75	pu
maximum inner loop feedback	Vgmax	999	pu

Notes:

1. The PSLF program requires the smallest time constant to be greater than 4 times the integration time step. For TR, TA < (4 x integration step), set TA=0 and TR=smallest allowable value. Kestrel suggests using 0.017 seconds as the smallest allowable value if the integration time step is 1/4 cycle.





A5 Power System Stabilizer Model

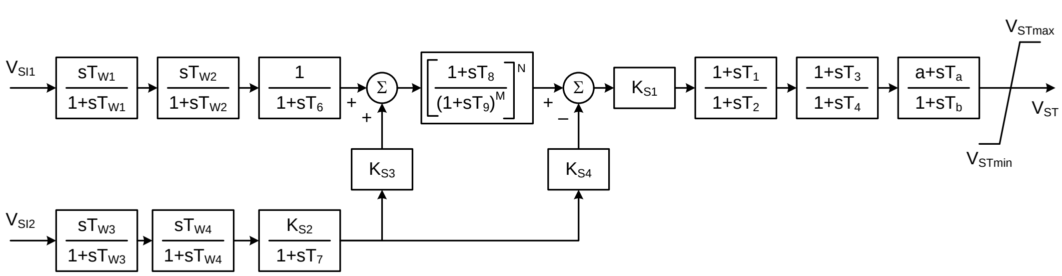
Power System Stabilizer Model IEEE 421.5 Std. PSS2A
PSLF Model PSS2A

Description	Parameter	Value	Units
first stabilizer input signal code	J1	1	
remote bus for first input signal	K1	0	
second stabilizer input signal code	J2	3	
remote bus for second input signal	K2	0	
input #1 first washout time constant	Tw1 (>0)	5	s
input #1 second washout time constant	Tw2	5	s
input #2 first washout time constant	Tw3(>0)	5	s
input #2 second washout time constant	Tw4	0	s
input #1 measurement time constant	T6	0	s
input #2 lag time constant	T7	5	s
input #2 gain	Ks2	0.9038	pu
gain	Ks3	1	pu
gain	Ks4	1	pu
ramp tracking filter numerator time constant	T8	0.5	s
ramp tracking filter denominator time constant	T9 (>0)	0.1	s
ramp track filter overall exponent	N	1	
ramp track filter denominator exponent	M	5	
PSS main gain	Ks1	8	pu
1st lead-lag numerator time constant	T1	0.1	s
1st lead-lag denominator time constant	T2	0.025	s
2nd lead-lag numerator time constant	T3	0.1	s
2nd lead-lag denominator time constant	T4	0.02	s
PSS max. output limit	Vstmax	0.1	pu
PSS min. output limit	Vstmin	-0.1	pu
4th lead-lag num. gain	a	1	pu
4th lead-lag num. time constant	Ta	0	s
4th lead-lag den. time constant	Tb	0	s

frequency compensation reactance	Xq comp	0.269	pu

Notes:

1. First input is compensated frequency calculated with the reactance Xq comp. The simulation model uses speed deviation as the first input, as compensated frequency is not available.
2. The parameter Tw4 is zero to indicate that the block is by-passed (block output=input)



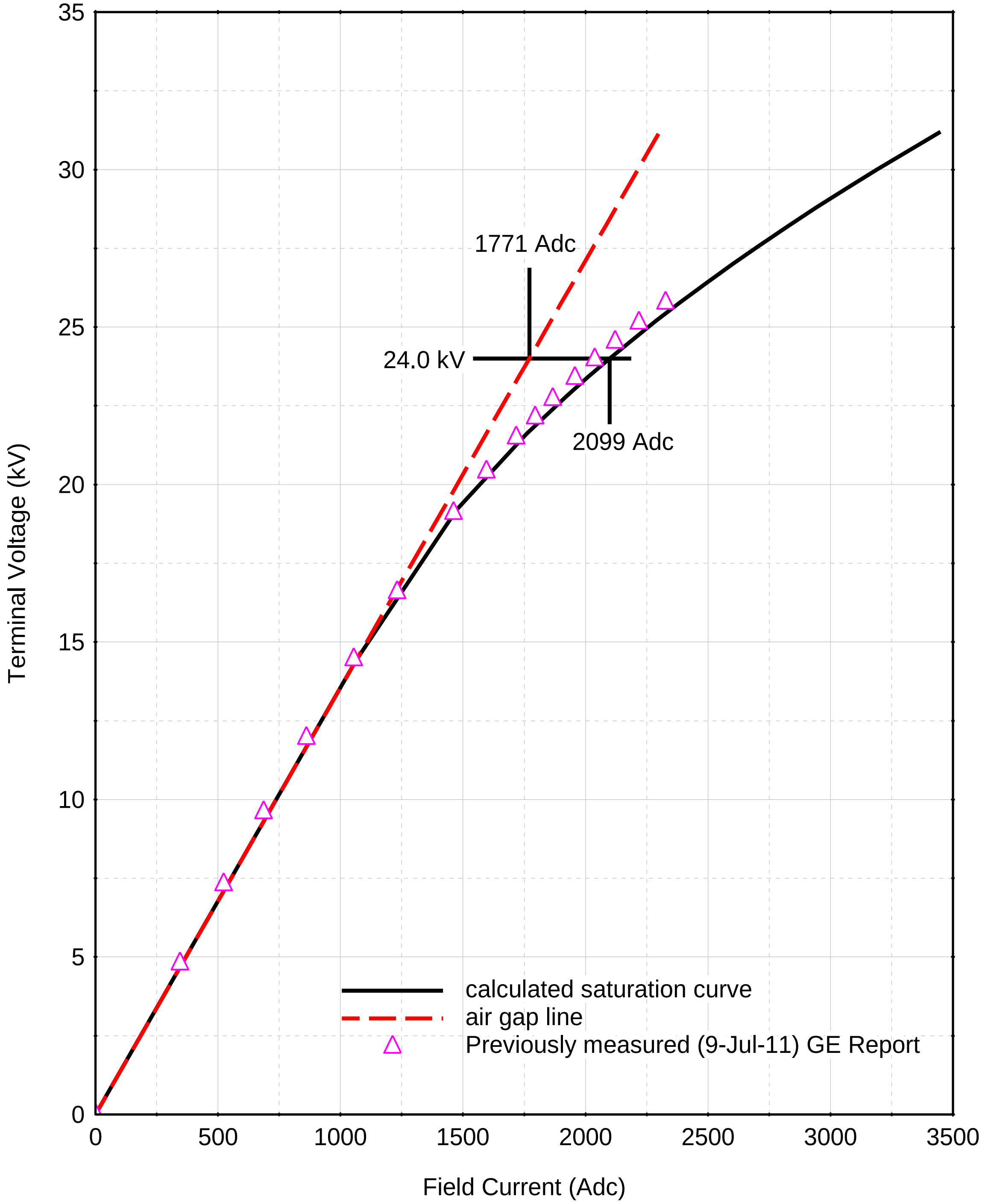
A6 Turbine Governor Model

*The unit should be represented in system studies as fixed mechanical power sources. The representation of a constant mechanical power from the turbine is usually automatically assumed when no explicit turbine/speed governor model is provided.

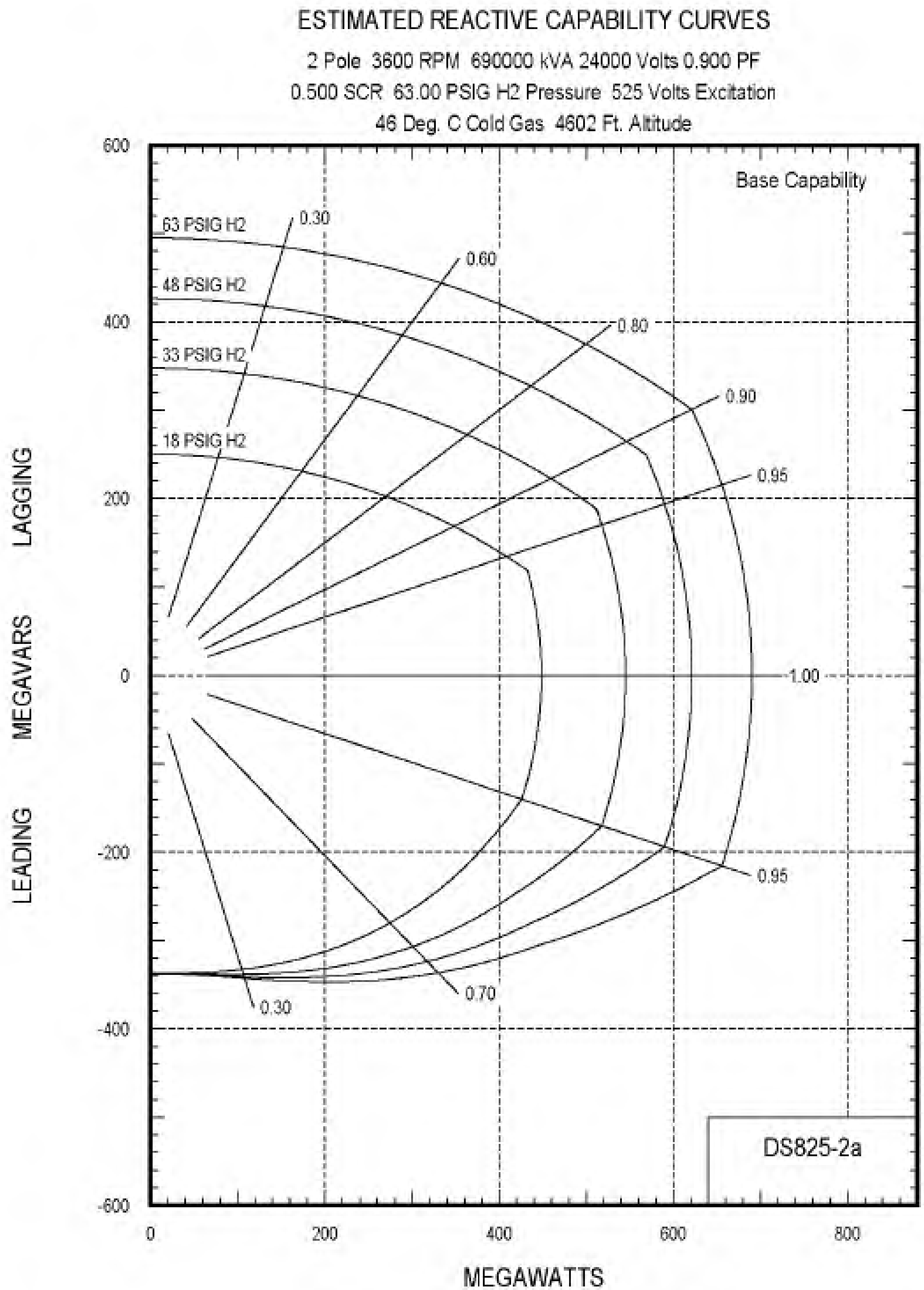
Thus, the fact that no explicit model has been provided implies that these units will be represented as fixed mechanical power sources and, as such, the requirements from NERC Std. MOD-027 are met.

APPENDIX B: CHARACTERISTIC CURVES

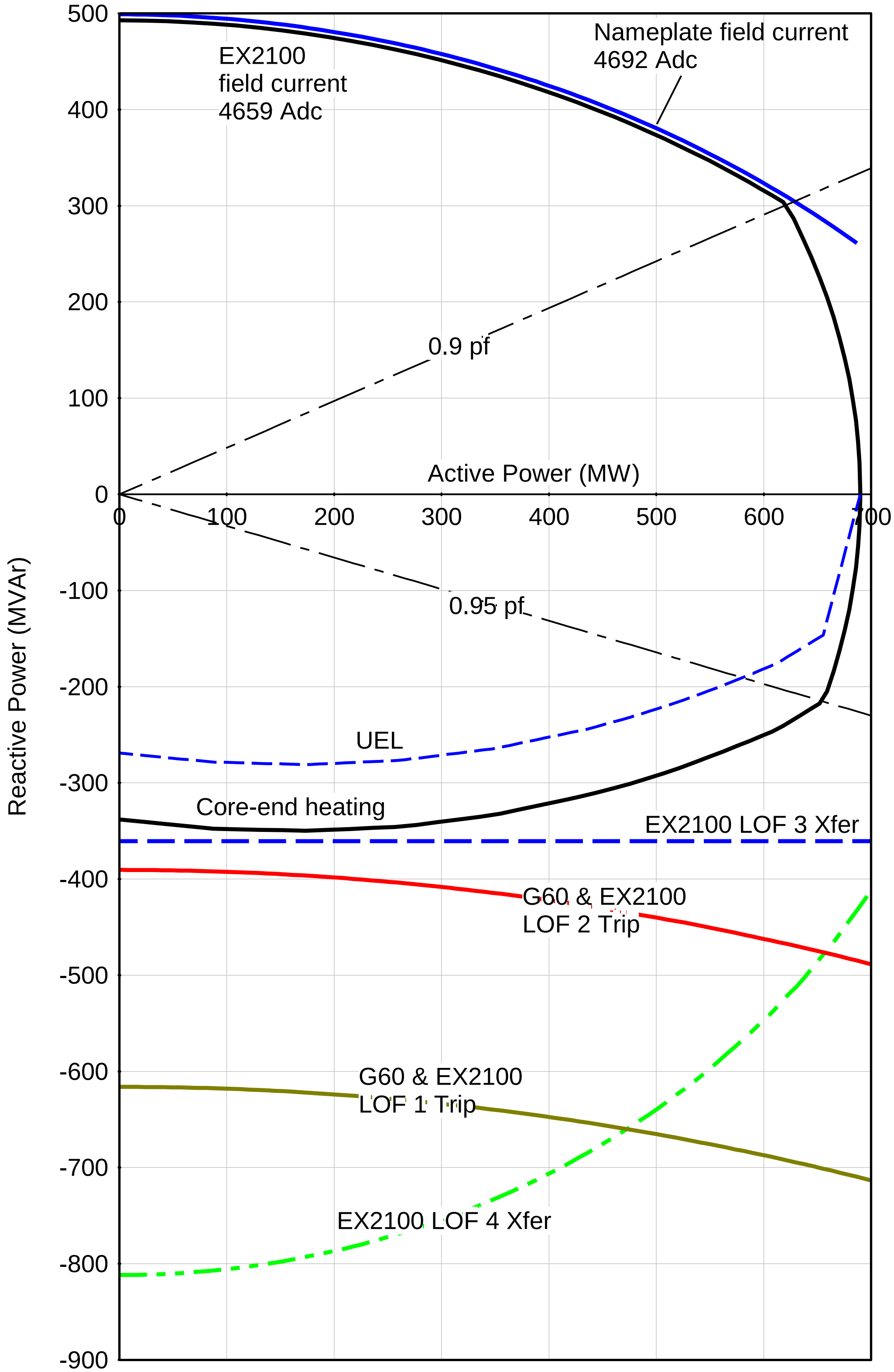
B1 Generator Open Circuit Saturation Characteristic



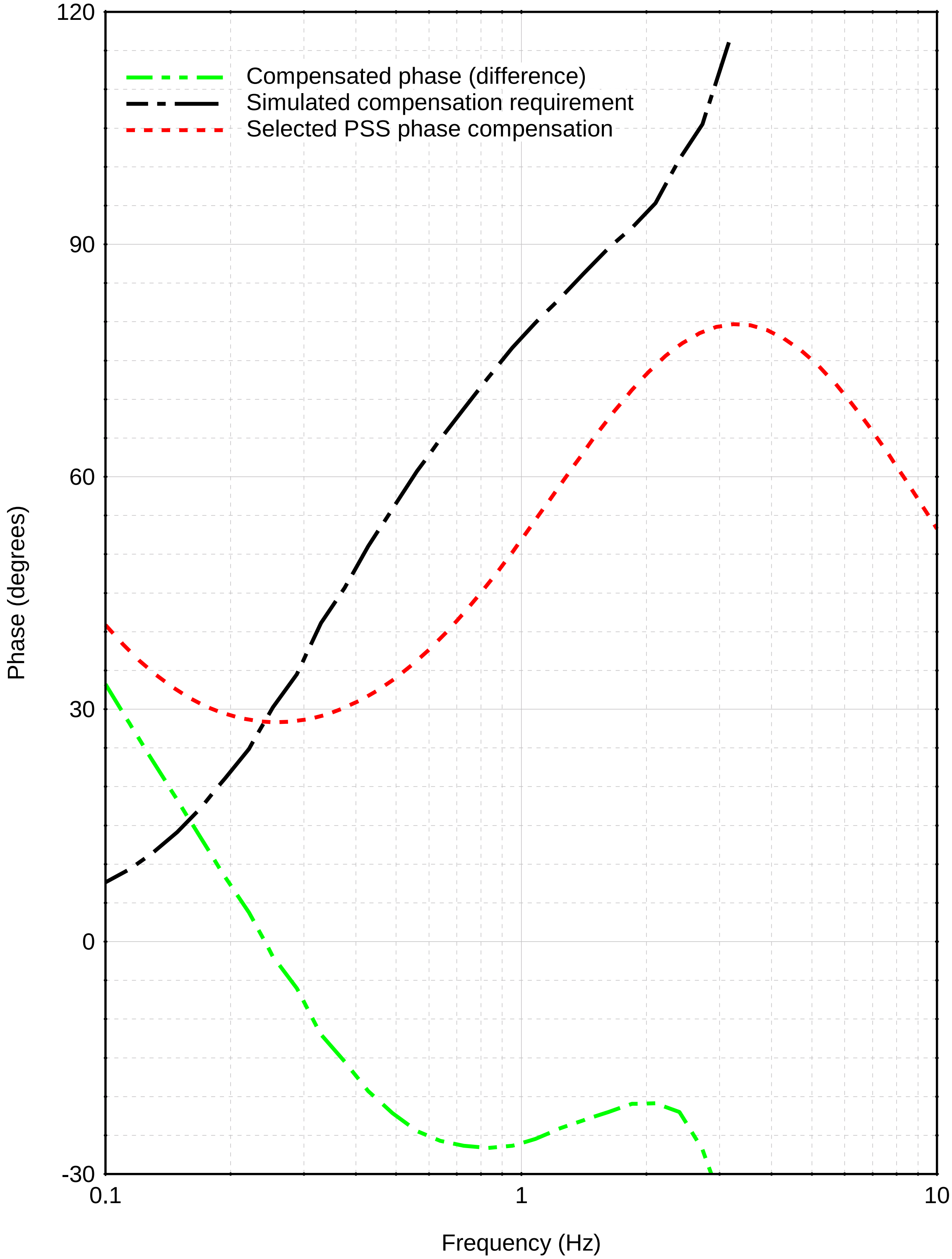
B2 Manufacturer's Generator Capability Curves



B3 Calculated Generator Capability and Coordination Curves, P-Q Plane

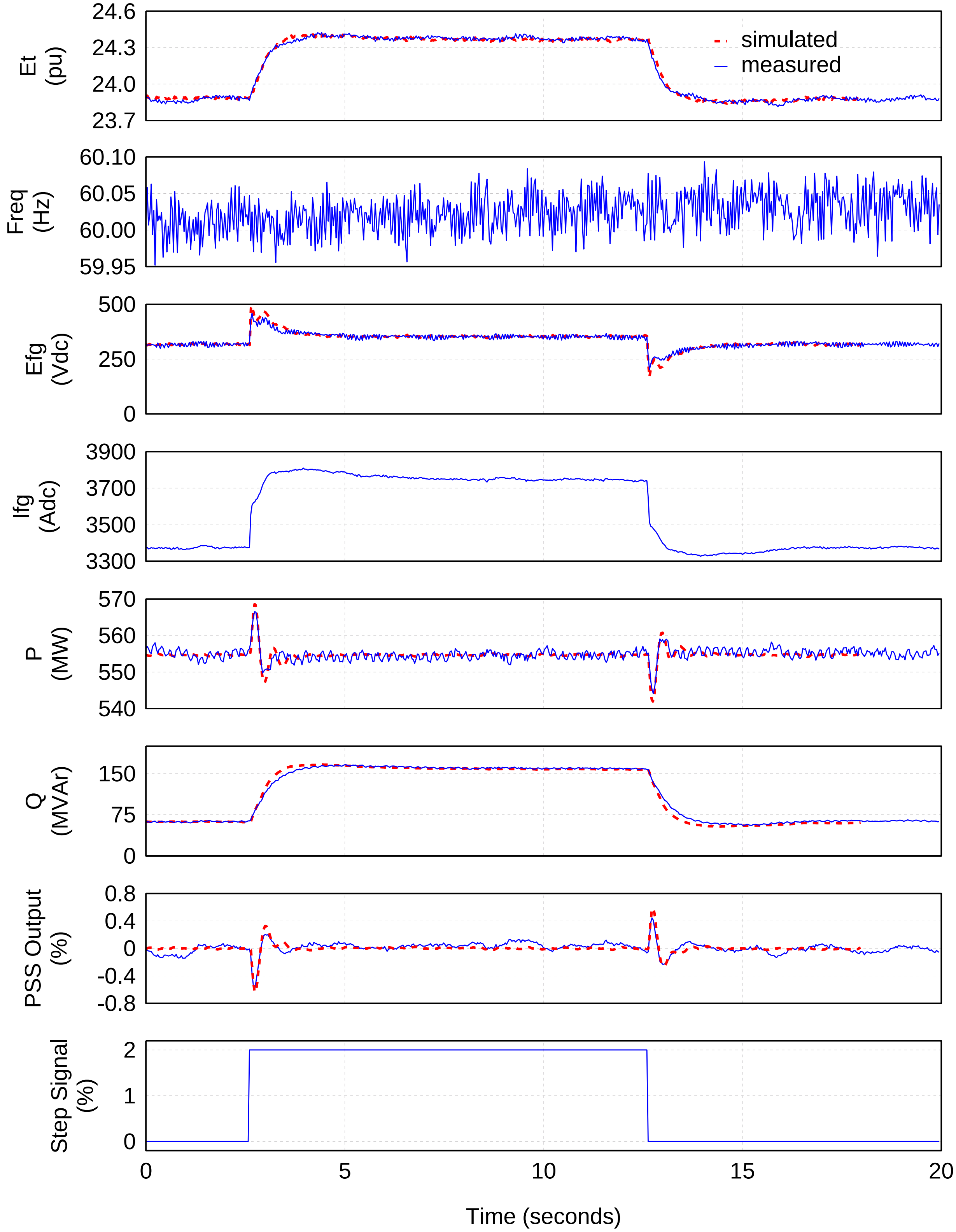


B4 Stabilizer Phase Compensation



APPENDIX C: MEASUREMENTS

C1 Online 2% AVR Step Response, Stabilizer Gain = 8 pu (As-Found Value)

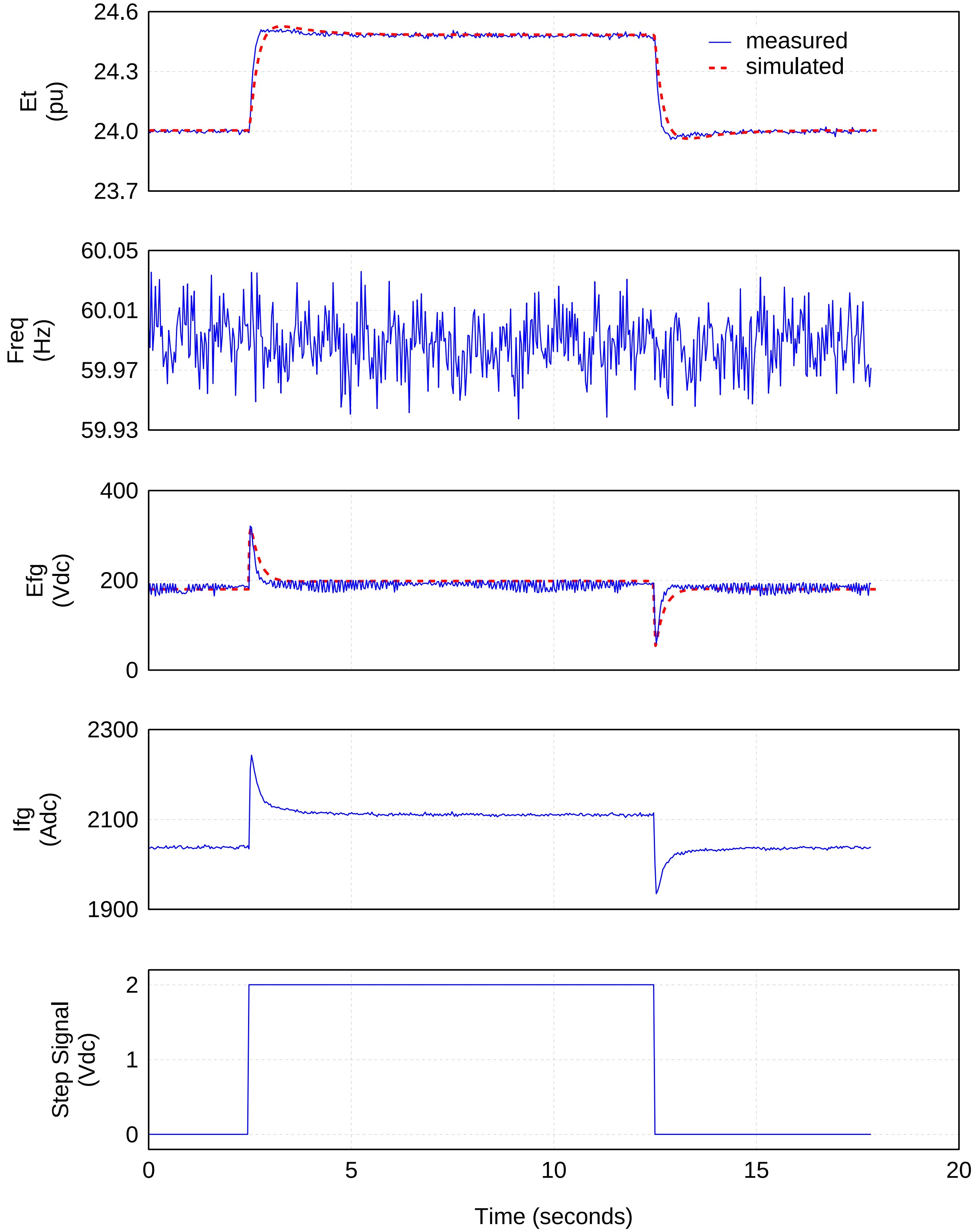


C2 Steady State Measurements

(MW)	(MVAr)	E (kV)	Ef (Vdc)	Ifg measured (Adc)	Ifg *calculated (Adc)*
632	281	24.82	453	4524	*4626*
628	-46	23.09	317	3316	*3413*
626	0	23.38	327	3431	*3536*
543	1	23.47	295	3137	*3228*
377	0	23.74	239	2615	*2687*
235	1	23.81	205	2267	*2335*
119	1	23.86	188	2083	*2152*
35	-4	23.76	178	1985	*2051*
26	-3	23.74	177	1978	*2047*
7	1	23.88	184	2013	*2086*
4	-118	23.16	120	1351	*1373*
556	355	24.81	461	4648	*4747*
557	-74	23.06	265	2941	*3044*
301	358	25.18	386	4212	*4295*
301	-248	23.02	131	1556	*1538*

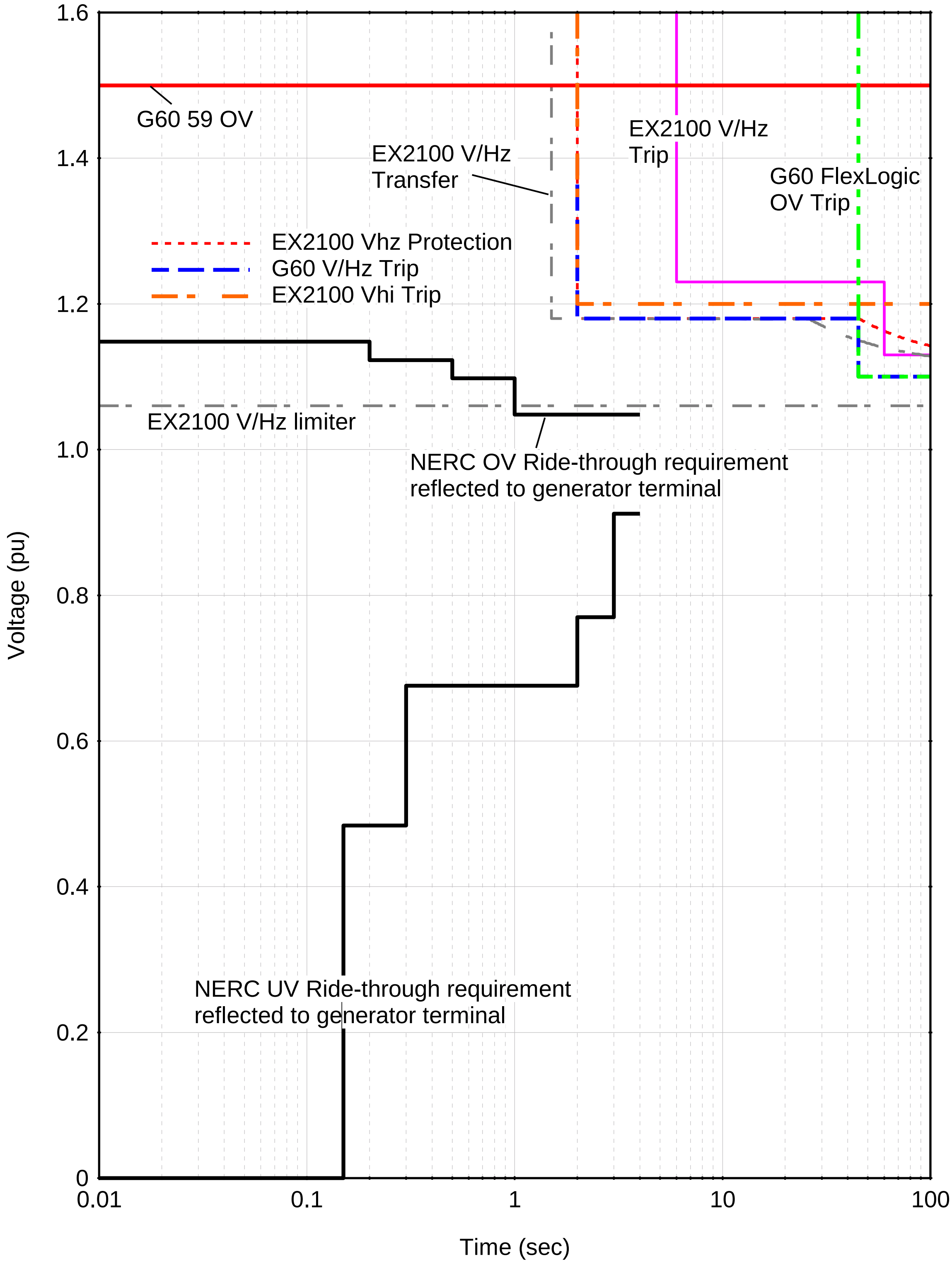
2011 measurements from GE report

C3 Open Circuit 2% AVR Step Response

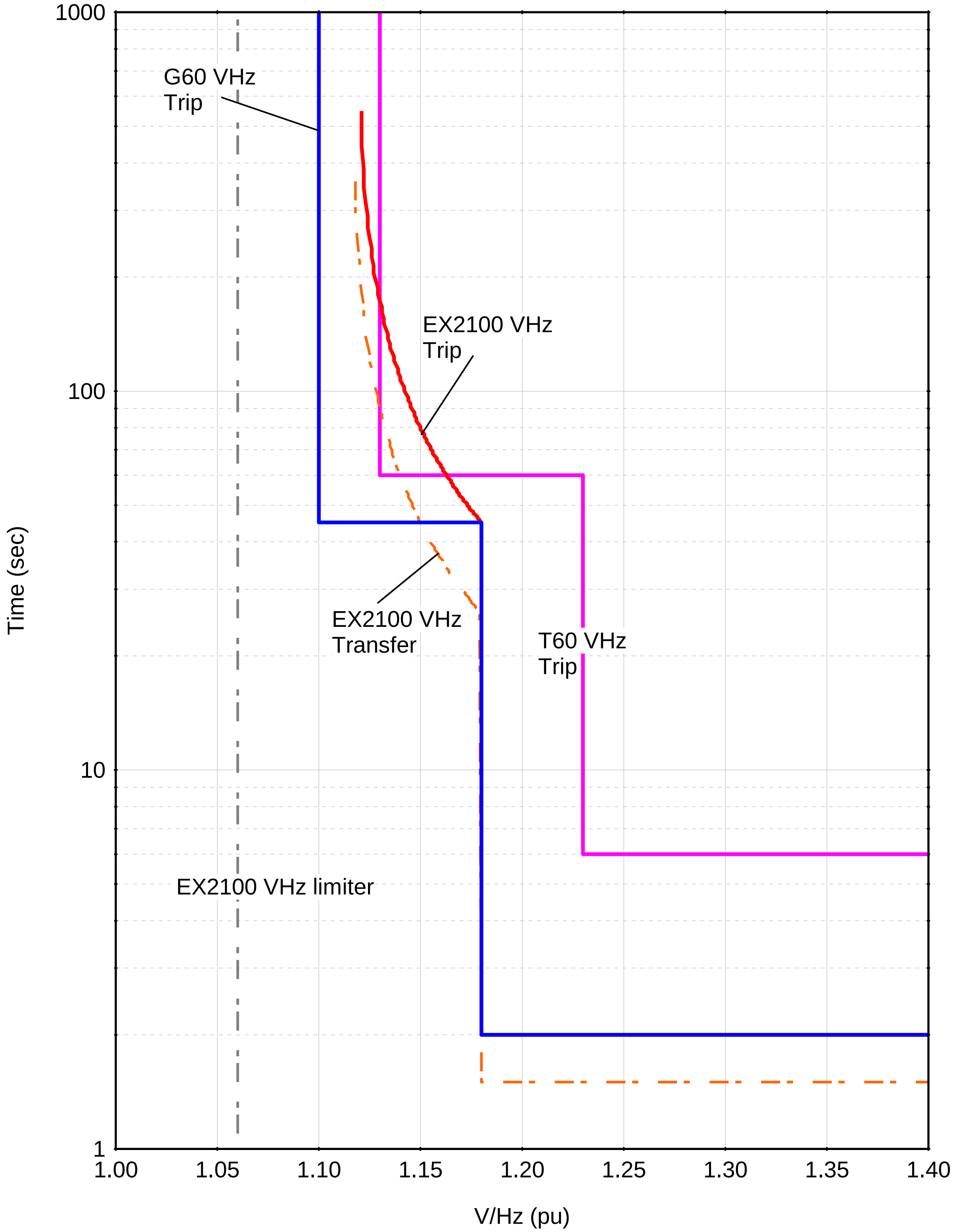


APPENDIX D: PROTECTION COORDINATION

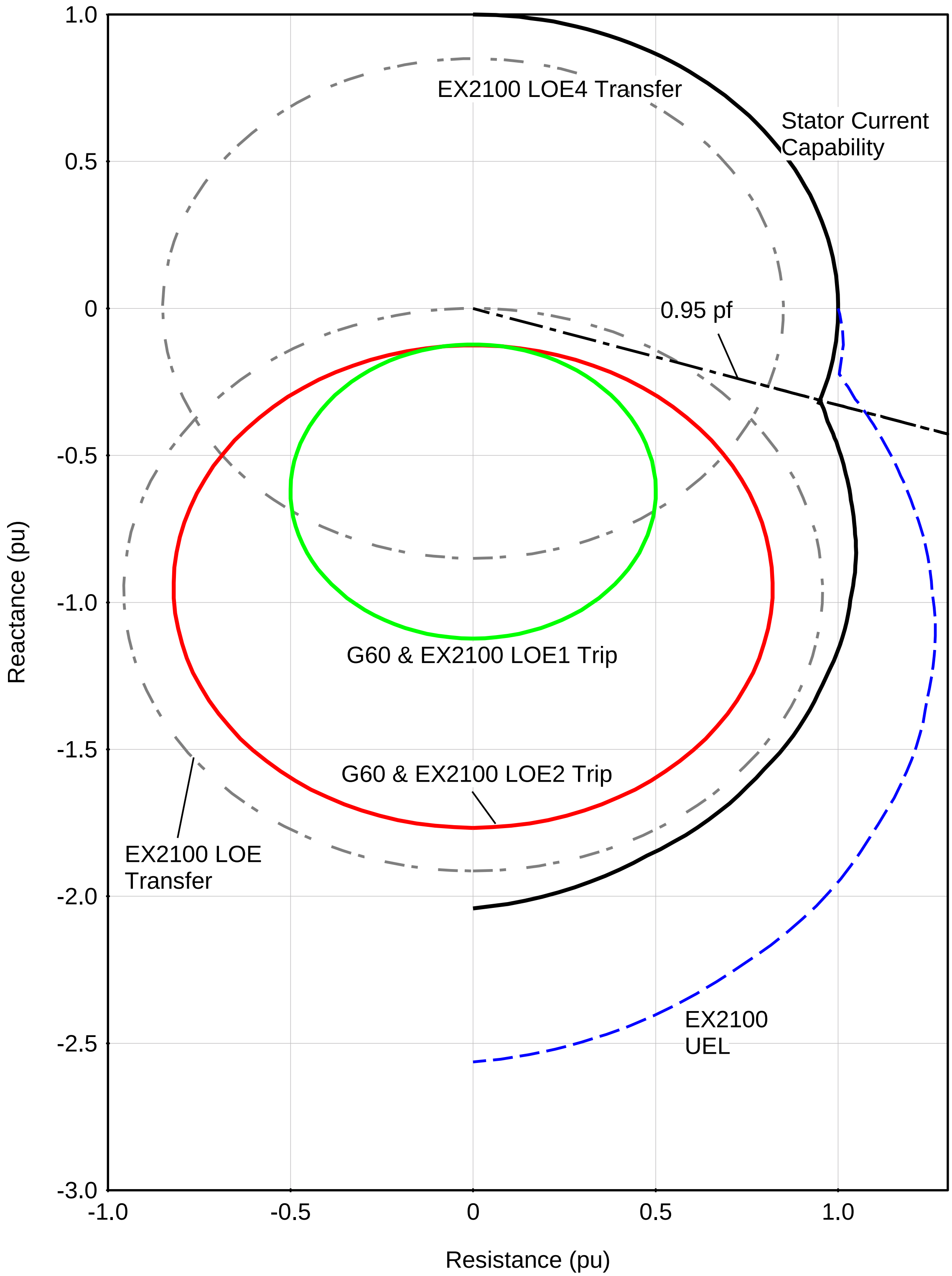
D1 Voltage Element Coordination



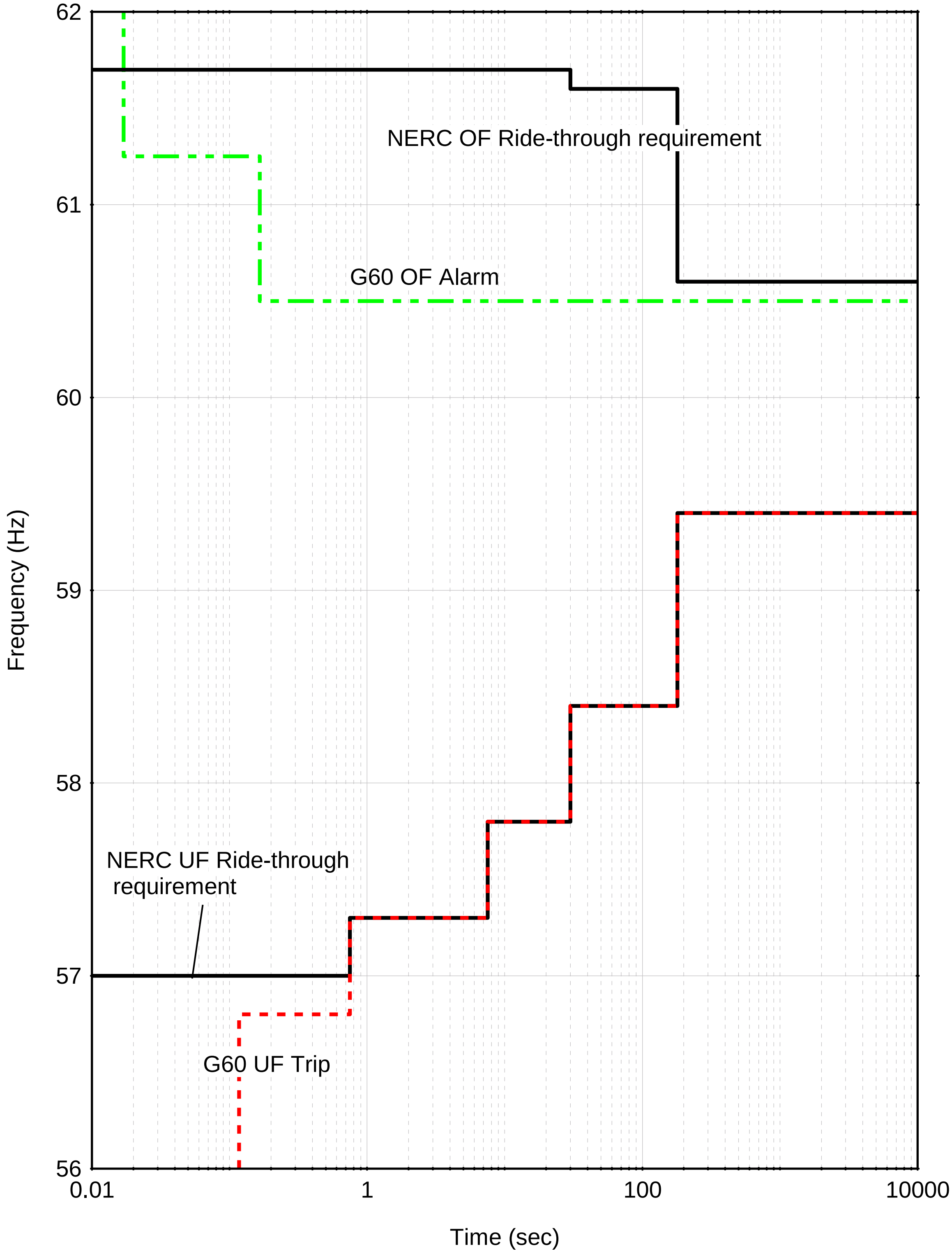
D2 V/Hz Element Coordination

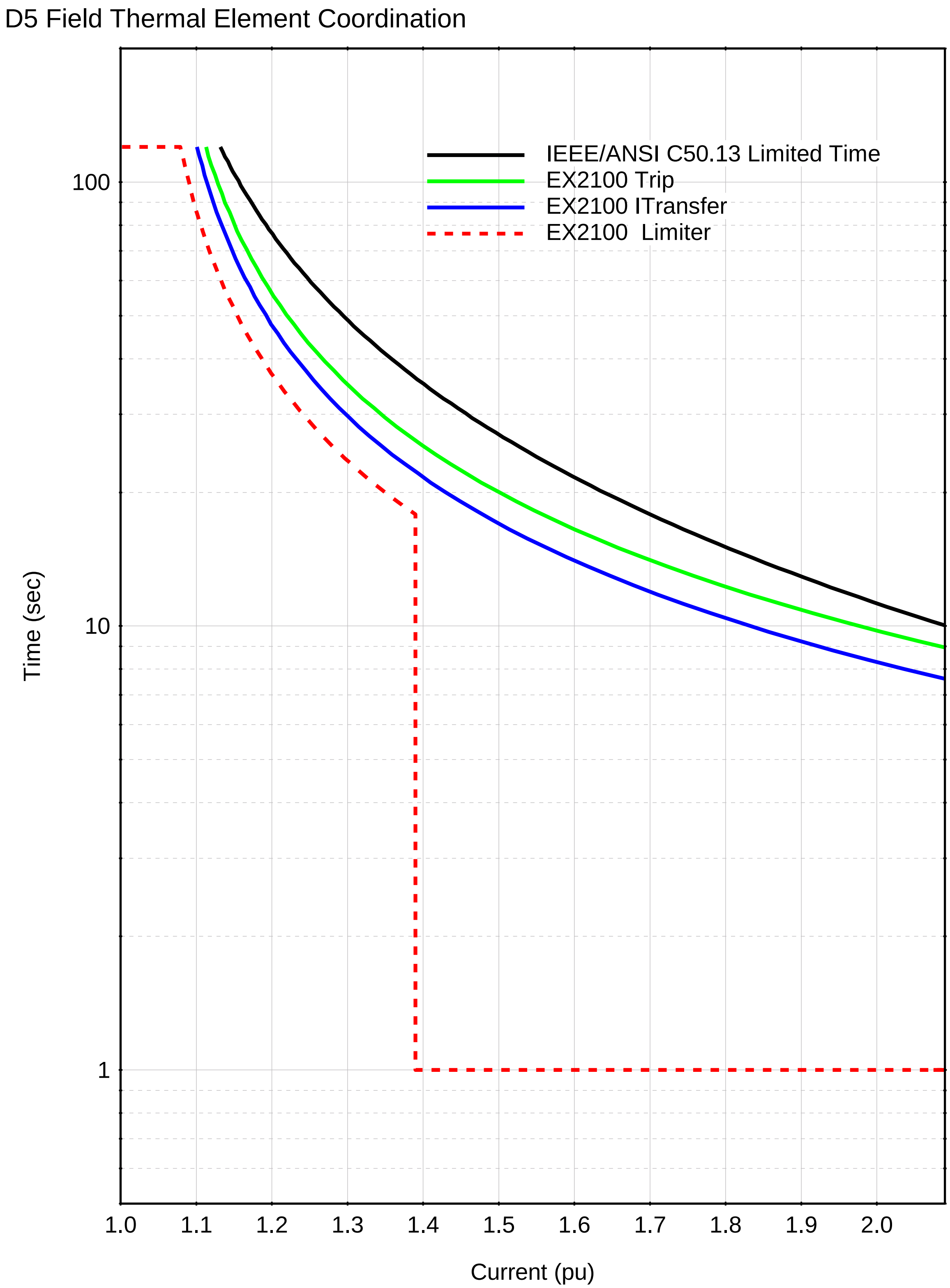


D3 Loss of Excitation Element Coordination



D4 Frequency Element Coordination




D5 Field Thermal Element Coordination
IEEE/ANSI C50.13 Limited Time
EX2100 Trip
EX2100 ITransfer
EX2100 Limiter
100
10
1
Time (sec)
1.0
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
Current (pu)

D6 Generator Relay Loadability Calculations

D6.1 Maximum Allowable Impedance Reach Calculations

Option 1a: V_{gen} = 22.23 kV, S = 610 + j931.5 MVA, Z Ratio = 0.05
Yields $\theta_{transient\ load\ angle}$ = 56.8°, Z_{pri} = 0.444 Ohms, Z_{sec} = 8.876 Ohms-secondary
$Z_{max} = Z_{sec} / (115\% \cdot \cos(\theta_{MTA} - \theta_{transient\ load\ angle}))$

Option 1b: V_{bus} = 22.61 kV, S = 610 + j931.5 MVA, Z Ratio = 0.05
Yields $\theta_{transient\ load\ angle}$ = 56.8°, Z_{pri} = 0.459 Ohms, Z_{sec} = 9.186 Ohms-secondary
$Z_{max} = Z_{sec} / (115\% \cdot \cos(\theta_{MTA} - \theta_{transient\ load\ angle}))$

Option 1b is used, since it provides the least restrictive requirement on maximum allowable impedance reach. *Note that the maximum allowable impedance reach is dependent on the maximum torque angle (θ_{MTA}) setting.*

Z1 angle = 89°, reach = 1.33 < 9.44 Ohms-secondary → ***PRC-025 Compliant***
Z2 angle = 86°, reach = 8.3 < 9.15 Ohms-secondary → ***PRC-025 Compliant***

D7 GSU Transformer (High-Voltage Side) Relay Loadability Calculations

D7.1 Maximum Allowable Impedance Reach Calculations

Option 14a: V_{bus} = 293.25 kV, S = 610 + j745.2 MVA, Z Ratio = 7.5
Yields $\theta_{transient\ load\ angle}$ = 50.7°, Z_{pri} = 89.297 Ohms, Z_{sec} = 11.906 Ohms-secondary
$Z_{max} = Z_{sec} / (115\% \cdot \cos(\theta_{MTA} - \theta_{transient\ load\ angle}))$

Note that the maximum allowable impedance reach is dependent on the maximum torque angle (θ_{MTA}) setting.

Line Z1 angle = 89°, reach = 3.07 < 13.19 Ohms-secondary → ***PRC-025 Compliant***

APPENDIX E: REACTIVE CAPABILITY FORMS

E1 NERC Reactive Capability Form

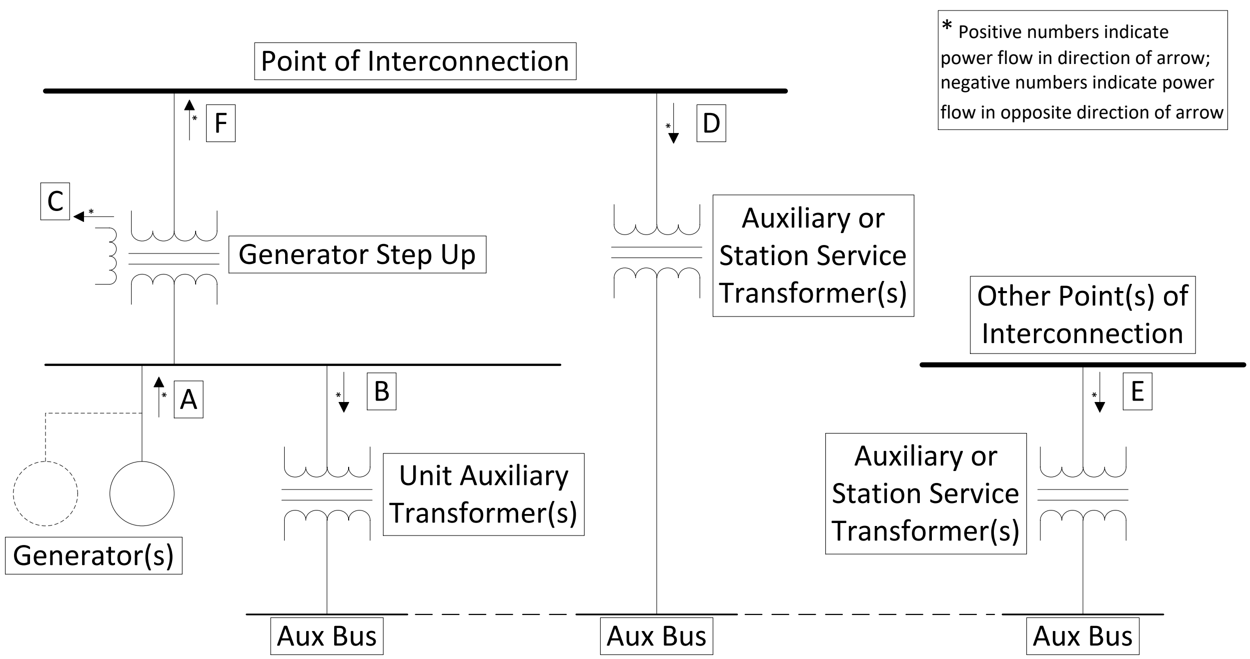
MOD-025 Attachment 2

Company: Basin Electric | Reported By: | On:
Plant: Laramie River Station | Unit No.: 3

Check all that apply:

- ☒ Under-Excited Minimum Load Reactive Power Verification
- ☒ Over-Excited Minimum Load Reactive Power Verification
- ☒ Under-Excited Maximum Load Reactive Power Verification
- ☒ Over-Excited Maximum Load Reactive Power Verification
- ☒ Real Power Verification
- ☒ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



E1.1 Under-Excited Minimum Load

Point	Voltage (kV)	P (MW)	Q (MVAr)	Comments
A	23.0	301	-248	**Generator:** Measured
B	6.95	28.3	17.59	**Unit Aux:** P & Q calculated using 0.85 pf
C	-	-	-	**tertiary from GSU:**
D	-	-	-	**Station Svc:**
E	-	-	-	**other POI:**
F	347	271	-294	**GSU high (net):** Measured

Limit: Under excitation limiter (UEL)

E1.2 Over-Excited Minimum Load

Point	Voltage (kV)	P (MW)	Q (MVAr)	Comments
A	25.2	301	358	**Generator:** Measured
B	7.1	29.2	18	**Unit Aux:** P & Q calculated using 0.85 pf
C	-	-	-	**tertiary from GSU:**
D	-	-	-	**Station Svc:**
E	-	-	-	**other POI:**
F	353	262	304	**GSU high (net):** Measured

Limit: 105% of rated generator terminal voltage

E1.3 Under-Excited Maximum Load

Point	Voltage (kV)	P (MW)	Q (MVAr)	Comments
A	23.1	556.6	-74.1	**Generator:** Measured
B	6.9	37.5	23.3	**Unit Aux:** P & Q calculated using 0.85 pf
C	-	-	-	**tertiary from GSU:**
D	-	-	-	**Station Svc:**
E	-	-	-	**other POI:**
F	341.5	514	-142	**GSU high (net):** Measured

Limit: Transmission line voltage on secondary line. TO requested to stop

E1.4 Over-Excited Maximum Load

Point	Voltage (kV)	P (MW)	Q (MVAr)	Comments
A	24.8	556.3	354.6	**Generator:** Measured
B	7.1	38.1	23.7	**Unit Aux:** P & Q calculated using 0.85 pf
C	-	-	-	**tertiary from GSU:**
D	-	-	-	**Station Svc:**
E	-	-	-	**other POI:**
F	348.8	507	274	**GSU high (net):** Measured

Limit: Rated generator field current (4659 Adc)

E1.5 Verification Data

	Data Recorded Lag/Lead
Gross Reactive Power Capability (*MVAR)	354.6/-74.1
Aux Reactive Power (*MVAR)	23.7/23.2
Tertiary Reactive Power (*MVAR)	N/A
[1]Net Reactive Power Capability (*MVAR)	274/-142
GSU Reactive Power Losses (*MVAR)	57/44.6
Gross Active Power Capability (*MW)	507/514
Aux Active Power (*MW)	38.1/37.5
Tertiary Active Power (*MW)	N/A
[1]Net Active Power Capability (*MW)	507/514

* Values from end of the verification period
[1] Note: Net Capability equals Gross Capability minus the sum of Aux Power and Tertiary Power connected at the same bus as well as GSU losses for Net Reactive Power Losses.

E1.6 Summary of Verification

Verification Date: 7-April-2017
Verification Start Time: 16:52
Verification Stop Time: 22:12
Scheduled Voltage: 1.01 pu (349 kV)

E1.7 Transformer Voltage Ratio:

GSU: 23.4-345 kV
Unit Aux: 24-6.9 kV
Station Aux: N/A
Other Aux: N/A

E1.8 Transformer Tap Setting:

GSU: D (100%)
Unit Aux: 100%
Station Aux: N/A
Other Aux: N/A

E1.9 Ambient Conditions at the end of verification period:

Air Temperature (°F): 59
Humidity: 36
Cooling Water Temp. (°F): N/A
Other Data, as applicable: Cooling gas temp = 41.8 C
Gen. Hydrogen Pressure at Time of Test: 63
Date of Last Verification: N/A

Remarks:
Minimum load: leading power factor measurements limited by the under excitation limiter (UEL), lagging power factor measurements limited by 105% of the rated generator terminal voltage.

Maximum load: leading power factor measurements limited by secondary transmission line voltage and request from transmission operator to stop lowering voltage, lagging power factor measurements limited by the rated generator field current (4659 Adc).

APPENDIX F: SETTINGS

F1 Excitation System Settings

Description	Variable Name	Value	Units
Rated generator terminal voltage	KV_Rated	24	kV
Rated generator MVA	MVA_Rated	690	MVA
Voltage Field Full Load	VFFL	510.63	Vdc
Voltage Field No Load	VFNL_Hot	213.39	Vdc
Amps Field Air-Gap	AFAG	1689	Adc
Amps Field No Load	AFNL	1947	Adc
Amps Field Full Load	AFFL	4659	Adc
Field Resistance at 125°C	RfldAt125C	0.1096	Ohms
Amps to produce 100mV on the shunt	ShuntAmps	7500	Adc
PPT Voltage	PPT_Vrms	1090	V
Auxiliary Bus Fed	AuxBusFed	FALSE	
Nominal value of PMG frequency	PMG_Freq	0	

Proportional Gain	AVRPGN	5.853	
Integral Gain	AVRIGN	5.853	r/s
Reactive Current Compensation	ASPRCC	0	pu
Volts/Hertz limit	ASPVHZ	1.060	pu
Output Upper Limit	ASPHLM	1.100	pu
Output Upper Limit	AVRPLM	1	pu
Output Lower Limit	AVRNLM	-0.800	pu

Amps Field Air-gap Exciter	AFAGE	1	Adc
Unloaded Exciter Output Voltage	V1L	0	Vdc
Open Circuit Voltage on Exciter Air-Gap (V1U)	ExVoltsOC	1	Vdc
Amps Field No Load Exciter	AFNLE	0	Adc
Amps Field Full Load Exciter	AFFLE	0	Adc
Unloaded exciter output voltage	V2U	0	Vdc
Amps Field Ceiling Exciter	AFCLE	0	Adc
Voltage Ceiling Loaded	V3L	0	Vdc
Voltage Ceiling Unloaded	V3U	0	Vdc
Voltage Field Air-Gap	ExVoltsOC	1	Vdc
Resistance of the Exciter	Rfe	0	ohms
Time Constant of the Exciter	Tfe	0	sec

Type of exciter and associated inner loop	ExciterType	PotentialFed	
Proportional Gain of FVR	FvrKp	0.000679579	
Integral Gain of FVR	FvrKi	0.033978932	r/s
Integral response of FVR Tracking	FvrTg	1	r/s
Intergral preset for FVR gating	FvrPreset	0.104677826	Edo
FVR Filter Time Constant	FvrFbLag	0.02	sec
Proportional Gain of FCR (non alternating)	FcrKp1	8.96061E-05	
Proportional Gain of FCR (alternating)	FcrKp2	8.96061E-05	
Integral Gain of FCR (non alternating)	FcrKi1	0.003378069	r/s
Integral Gain of FCR (alternating)	FcrKi2	0.003378069	r/s
Integral preset of FCR gating (non alternating)	FcrPreset1	0.250484854	
Integral preset of FCR gating (alternating)	FcrPreset2	0.125613391	
FCR Feedback lead term time constant	FcrFbLead	0	sec
FCR Feedback lag term time constant	FcrFbLag	0	sec

Type of exciter and associated inner loop	RegType		
Scaling factor from Field Current to Reg Current	FctoRcScale	1	
Regulator Current Regulator Proportional Gain	RcrKp	0	
Regulator Current Regulator Integral Gain	RcrKi	0	

Description	Variable Name	Value	Units
UEL Curve Real Power Point 1	UELX0	0	pu
UEL Curve Real Power Point 2	UELX1	0.1267	pu
UEL Curve Real Power Point 3	UELX2	0.2533	pu
UEL Curve Real Power Point 4	UELX3	0.3800	pu
UEL Curve Real Power Point 5	UELX4	0.5067	pu
UEL Curve Real Power Point 6	UELX5	0.6334	pu
UEL Curve Real Power Point 7	UELX6	0.6967	pu
UEL Curve Real Power Point 8	UELX7	0.7600	pu
UEL Curve Real Power Point 9	UELX8	0.8234	pu
UEL Curve Real Power Point 10	UELX9	0.8867	pu
UEL Curve Real Power Point 11	UELX10	0.9500	pu
UEL Curve Reactive Power Point 1	UELY0	-0.4900	pu
UEL Curve Reactive Power Point 2	UELY1	-0.5035	pu
UEL Curve Reactive Power Point 3	UELY2	-0.5074	pu
UEL Curve Reactive Power Point 4	UELY3	-0.5008	pu
UEL Curve Reactive Power Point 5	UELY4	-0.4831	pu
UEL Curve Reactive Power Point 6	UELY5	-0.4533	pu
UEL Curve Reactive Power Point 7	UELY6	-0.4337	pu
UEL Curve Reactive Power Point 8	UELY7	-0.4107	pu
UEL Curve Reactive Power Point 9	UELY8	-0.3844	pu
UEL Curve Reactive Power Point 10	UELY9	-0.3546	pu
UEL Curve Reactive Power Point 11	UELY10	-0.3123	pu
Margin above the plotted curve	MARGIN	0.1000	pu
UEL Proportional Gain	UELPGN	0.8000	
UEL Integral Gain	UELIGN	0.5	r/s
UEL Output Upper Limit	UELPLM	0.25	pu
UEL Output Lower Limit	UELNLM	0	pu
Real Power Stator Limit Reference Line Point 1	STAT_W1	0.9500	pu
Real Power Stator Limit Reference Line Point 2	STAT_W2	1	pu
Reactive Power Stator Limit Reference Line Point 1	STAT_V1	-0.2123	pu
Reactive Power Stator Limit Reference Line Point 2	STAT_V2	0	pu

Level for field OE trip relay accumulation	OE_PU	4752.2	Adc
Level for field OE trip relay infinite	OE_Inf	4938.5	Adc
Level for OE trip at OETripSec	OETripLev	5218.1	Adc
Time for field OE trip relay activation	OETripSec	120	sec
Percent of trip level to activate OEL	OELimitLev	70	%
Percent of trip level to force master xfr	OEXferLev	85	%
OE Trip Enabled	TripOELTrip	Trip	
OE Transfer Enabled	XferOELXfer	Transfer	
Level for straight time protection active	FldCurHiSet	6522.6	Adc
Time required for straight time to activate	FldCurHiSec	1	sec
Level for straight time protection deactivate	FldCurHiRes	5124.9	Adc
Set point for FCR at straight time active	FcrRefHi	5823.8	Adc
Set point for FCR at inverse time active	FcrRefLo	4659	Adc

LOE1 Trip enable Boolean	TripLOE1Trip	Trip	
LOE1 Impedance diameter	LOE1_XD	1	pu
LOE1 Impedance offset	LOE1_XO	0.120	pu
LOE1 Delay time	LOE1Sec	0.050	sec
LOE2 Trip enable Boolean	TripLOE2Trip	Trip	
LOE2 Impedance diameter	LOE2_XD	1.674	pu
LOE2 Impedance offset	LOE2_XO	0.120	pu
LOE2 Delay time	LOE2Sec	0.5	sec
LOE3 Transfer enable Boolean	XferLOE3Xfer	Transfer	

LOE3 Impedance diameter	LOE3_XD	1.914	pu
LOE3 Impedance offset	LOE3_XO	0	pu
LOE3 Delay time	LOE3Sec	0.5	sec
LOE4 Transfer enable Boolean	XferLOE4Xfer	Transfer	
LOE4 Impedance diameter	LOE4_XD	1.700	pu
LOE4 Impedance offset	LOE4_XO	-0.850	pu
LOE4 Delay time	LOE4Sec	0.5	sec

Description	Variable Name	Value	Units
V/Hz level for straight time trip	VHz1TripLev	1.180	pu
Time for V/Hz straight time trip	VHz1TripSec	2	sec
V/Hz1 trip enable	TripVHz1Trip	Trip	
V/Hz level for inverse time trip	VHz2TripLev	1.180	pu
Time for V/Hz inverse time trip	VHz2TripSec	45	sec
Level for trip relay to pick up at infinite time	VHz2TripInf	1.120	pu
Level for trip relay to start accumulation	VHz2TripPU	1.100	pu
V/Hz2 trip enable	TripVHz2Trip	Trip	
V/Hz level for straight time transfer	VHz3XferLev	1.180	pu
Time for V/Hz straight time transfer	VHz3XferSec	1.5	sec
V/Hz3 transfer enable	XferVHz3Xfer	Transfer	
Percent of V/Hz inverse-time trip to force transfer	VHz4XferLev	85	%
V/Hz4 transfer enable	XferVHz4Xfer	Transfer	
High voltage straight time trip	VHiTripLev	1.200	pu
Time for high voltage straight time trip	VHiTripSec	2	sec
High voltage trip enable	TripVHiTrip	Trip	

Description	Variable Name	Value	Units
Type (0=No PSS, 1=PSS1A, 2=PSS2A)	PSS_Type	2	
Final Output Gain of Stabilizer	PSSGN	8	
Lead time constant of Lead/Lag block 1	PSSLD1	0.100	sec
Lag time constant of Lead/Lag block 1	PSSLG1	0.025	sec
Lead time constant of Lead/Lag block 2	PSSLD2	0.100	sec
Lag time constant of Lead/Lag block 2	PSSLG2	0.02	sec
Lead time constant of Lead/Lag block 3	PSSLD3	0	sec
Lag time constant of Lead/Lag block 3	PSSLG3	0	sec
Washout Time Constant	PSSWO	5	sec
PSS Inertia (2H or M)	INERTIA	5.532	MW-s/MVA
Ramp tracking filter time constant	RTF_TC	0.100	sec
Compensation for PSS Slip Calculation	XqSlip	0.269	pu
PSS Output Upper Limit	PSSPLM	0.100	pu
PSS Output Lower Limit	PSSNLM	-0.100	pu
PSS Enable Power Level	WATTSHI	0.200	pu
PSS Disable Power Level	WATTSLO	0.150	pu
Biquad 1 Numerator Damp	PSSB1D1	0.050	
Biquad 1 Nenomenator Damp	PSSB1D2	0.25	
Biquad 1 Nat R/S	PSSB1W0	114	
Biquad 2 Numerator Damp	PSSB2D1	0.050	
Biquad 2 Denomenator Damp	PSSB2D2	0.25	
Biquad 2 Nat R/S	PSSB2W0	126.600	
Biquad 3 Numerator Damp	PSSB3D1	0.5	
Biquad 3 Denomenator Damp	PSSB3D2	0.5	
Biquad 3 Nat R/S	PSSB3W0	62	

F2 Protection Settings

PT and CT Ratios

Description	Value
Protection PT ratio	200
Protection CT ratio	4000
GSU High Side PT ratio	200
GSU High Side CT ratio	240
PPT Primary CT ratio	100
PPT Secondary CT ratio	1

40 Loss-of-Excitation Element Settings

Description	Status	Settings
G60 LOE1 Trip	Trip	Time delay: 0.07, Radius 8.35, Center (R, X) 0, -10.4 secondary ohms
G60 LOE2 Trip	Trip	Time delay: 0.5, Radius 13.7, Center (R, X) 0, -15.8 secondary ohms
IEEE2 LOE	Limit	Units: MVAr
IEEE1 LOE	Limit	Units: MVAr
EX2100 UEL	Limit	P(pu) , Q(pu): 0, -0.49, 0.1267, -0.5035, 0.2533, -0.5074, 0.38, -0.5008, 0.5067, -0.4831, 0.6334, -0.4533, 0.6967, -0.4337, 0.76, -0.4107, 0.8234, -0.3844, 0.887, -0.355, 0.95, -0.312, Limit1 P: 0.95, Limit1 Q: -0.212, Limit2 P: 1, Limit2 Q: 0, Q margin: 0.1, Units: pu
EX2100 LOE1 Trip	Trip	Time delay: 0.05, Diameter 1, Offset -0.12 pu
EX2100 LOE2 Trip	Trip	Time delay: 0.5, Diameter 1.674, Offset -0.12 pu
EX2100 LOE3 Transfer	Channel Transfer	Time delay: 0.5, Diameter 1.914, Offset 0 pu
EX2100 LOE4 Transfer	Limit	Radius 0.85, Center (R, X) 0, 0 pu

24 V/Hz Element Settings

Description	Status	Settings
G60 V/Hz Trip	Trip	Time(sec) , V/Hz(pu): 2, 1.18, 45, 1.1
EX2100 Vhz Protection	Trip	VHZ1_TRIP: 1.18, VHZ1_SEC: 2, VHZ2_INF: 1.12, VHZ2_TRIP: 1.18, VHZ2_PU: 1.1, VHZ2_SEC: 45, Units: pu
EX2100 Vhz limiter	Limit	Time(sec) , V/Hz(pu): 0, 1.06
EX2100 Vhz transfer	Channel Transfer	VHZ1_TRIP: 1.18, VHZ1_SEC: 1.5, VHZ2_INF: 1.117, VHZ2_TRIP: 1.15, VHZ2_PU: 1.1, VHZ2_SEC: 45, Units: pu
T60 V/Hz Trip	Trip	Time(sec) , V/Hz(pu): 60, 1.13, 6, 1.23

59/27 Over/Under-Voltage Element Settings

Description	Status	Settings
G60 Phase OV1 Trip recommended	Trip	Time(sec) , V(pu): 0, 1.5
G60 FlexLogic Trip	Trip	Time(sec) , V(pu): 45, 1.1
EX2100 Vhi Trip	Trip	Time(sec) , V(pu): 2, 1.2
G60 Phase OV1 Trip actual	Trip	Time(sec) , V(pu): 0, 1.5

81 Over/Under-Frequency Element Settings

Description	Status	Settings
G60 Underfrequency Trip recommended	Trip	Time(sec) , F(Hz): 0.117, 56.8, 0.75, 56.8, 0.75, 57.3, 7.5, 57.3, 7.5, 57.8, 30, 57.8, 30, 58.4, 180, 58.4, 180, 59.4
G60 Overfrequency alarm	Trip	Time(sec) , F(Hz): 0.017, 61.25, 0.166, 61.25, 0.166, 60.5

51ET Excitation Over-Current Element Settings

Description	Status	Settings
EX2100 OE Standard Curves	Trip	CurveShape: Transfer, OETripLev: 1.12, OELimitLev: 70%, OE_Inf: 1.06, OE_PU: 1.02, OETripSec: 120, FldCurHiSet: 1.4, FldCurHiSec: 1, FldCurHiRes: 1.1, FcrRefLo: 1, FcrRefHi: 1.25, Units: pu

50/51 Stator Current Element Settings

Description	Status	Settings
G60 50IOC	Trip	Time(sec) , I(pu): 0.5, 1.0844

APPENDIX G: GLOSSARY

G1 Acronyms

AVR Automatic Voltage Regulator
CT Current Transformer
FCR Field Current Regulator
HIR High Initial Response
LOE Loss of Excitation relay (40)
MEL Minimum Excitation Limiter (also called UEL or URAL in some texts)
MOT Main Output Transformer
OEL Over Excitation Limiter
PF Power Factor (usually used in the context of power factor regulator or controller)
PID Proportional Integral Derivative
PPT Power Potential Transformer (used by some vendors to refer to static excitation system power transformer)
PSS Power System Stabilizer
PT Potential Transformer
RCC Reactive Current Compensation
SCL Stator Current Limiter
UEL Under Excitation Limiter
V/Hz Volts-Per-Hertz Limiter
VAR Reactive Power (usually used in the context of VAR regulator or controller)

G2 Symbols and Variables

The following is a list of common symbols and variables appearing in generator test reports. Where appropriate the normal units of measure have been included in parentheses. If duplicate definitions exist for a symbol, they are listed with an indication of the context.

E_{fg} generator field voltage (Vdc) (in some references Efd for generator field voltage direct axis)
E_{fe} main exciter field voltage (Vdc) (in most rotating exciter block diagrams denoted Vr)
E_t generator ac three-phase terminal voltage (kV)
E_{tref} terminal voltage reference (kV)
F generator terminal frequency or compensated frequency (Comp Freq) (Hz)
I current
I_{fg} generator field current (Adc)
I_{fe} main exciter field current (Adc)
I_t generator ac terminal current (kA)
K_a AVR gain (pu E_{fd} / pu E_{tref})
K_c rectifier loading factor (pu)
K_P proportional gain
K_I integral gain
K_D derivative gain
P active power (in some documents referred to as real power) (MW)
Q reactive power (in some documents referred to as imaginary power) (MVAr)
R_c resistive load compensation component
R_{fg} generator field winding resistance (Ω)
R_{fe} main exciter field winding resistance (Ω)
R_P governor permanent droop
R_t governor temporary droop
S apparent power (MVA)
T_r exciter terminal voltage feedback time constant (s)
V, E voltage
V_c compensated terminal voltage feedback signal (pu E_{tref})
ω speed (Greek symbol omega) (pu)
X impedance, per unit
X_c reactive load compensation component

Exhibit No. TS-023

Limon Units 1-2

MOD-025 Test Reports and Capability Curves

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

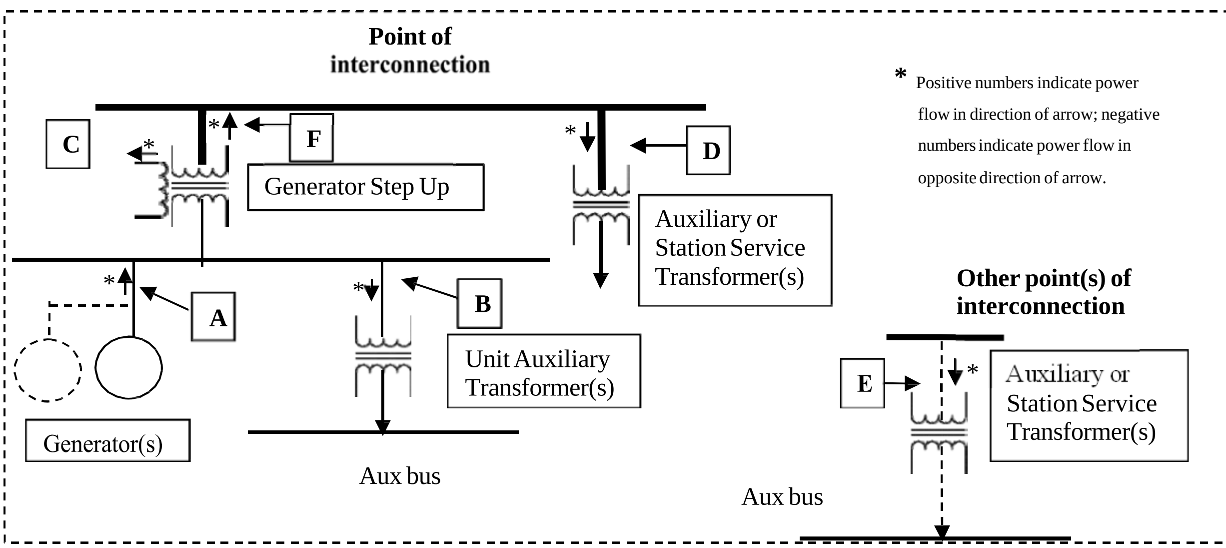
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: Limon Generating Station **Unit: 1** **Date of Report: 07/21/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A1	**12.92 kV**	**39.5 MW**	**-32.1 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**0.449 kV**	**0.318 MW**	**0.271 Mvar**	Unit Auxiliary Transformer
Identify calculated values, if any:				
F1	**233.3 kV**	**38.5 MW**	**-39.5 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A1	**15.0 kV**	**40.2 MW**	**43.9 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**0.522 kV**	**0.331 MW**	**0.384 Mvar**	Unit Auxiliary Transformer
Identify calculated values, if any:				
F1	**242.1 kV**	**40.5 MW**	**38.0 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A1	**13.1 kV**	**66.3 MW**	**-23.7 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**0.456 kV**	**0.334 MW**	**0.255 Mvar**	Unit Auxiliary Transformer
Identify calculated values, if any:				
F1	**233.0 kV**	**68.3 MW**	**-21.9 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A1	**14.9 kV**	**66.1 MW**	**45.5 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**0.522 kV**	**0.356 MW**	**0.400 Mvar**	Unit Auxiliary Transformer
Identify calculated values, if any:				
F1	**241.5 kV**	**66.9 MW**	**35.2 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-32.1	
GSU Reactive Power (Mvar)	7.4	
Net Leading Reactive Power Capability (Mvar)	-39.5	
Gross Lagging Reactive Power Capability (Mvar)	45.5	
GSU Lagging Reactive Power (Mvar)	-10.3	
Net Lagging Reactive Power Capability (Mvar)	35.2	
Gross Real Power Capability Minimum Stable Load (MW)	39.9	
Gross Real Power Capability Maximum output (MW)	66.3	
Station Service Reactive Load (Mvar)	0.255	
Station Service Real Load (MW)	0.334	
Net Unit Maximum Real Power Output (MW)	65.3	
GSU Real Power Losses (MW)	0.90	
GSU Reactive Losses (Mvar)	-6.500	

Summary of Verification

- Date of Verification: 07/19/2016
- Verification Start Time: 12:02
- Verification End Time: 14:55
- Scheduled Voltage: 230 kV
- Transformer Voltage Ratio:
  - GSU: 16.667
  - Station Service: 29.469
  - Cranking Motor: 3.389
- Transformer Tap Setting:
  - GSU: 3
  - Station Service: 2
  - Cranking Motor: 2

- Ambient conditions at the end of the verification:
  - Air temperature: 93.4 °F
  - Humidity: 22 %

Date that data shown in last verification column in table above was taken: 06/19/2016

Remarks :

UEL and OEL was reached for all testing.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

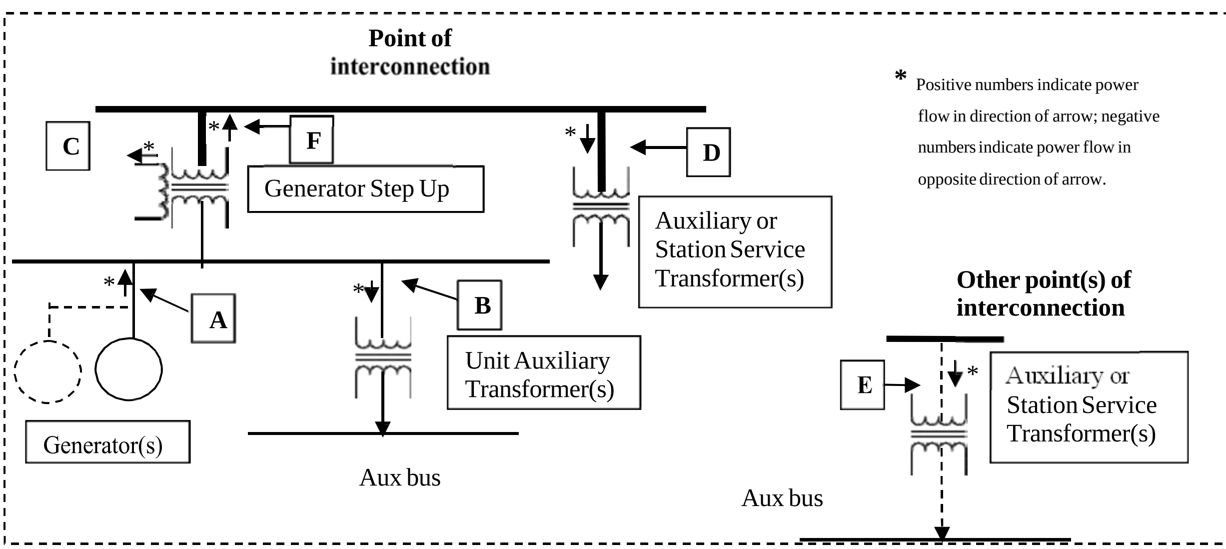
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: Limon Generating Station **Unit: 2** **Date of Report: 07/21/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A2	**12.98 kV**	**39.9 MW**	**-32.6 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**0.451 kV**	**0.133 MW**	**0.169 Mvar**	Unit Auxiliary Transformer
Identify calculated values, if any:				
F2	**233.3 kV**	**38.3 MW**	**-38.5 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A2	**15.0 kV**	**40.0 MW**	**46.5 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**0.522 kV**	**0.222 MW**	**0.159 Mvar**	Unit Auxiliary Transformer
Identify calculated values, if any:				
F2	**243.6 kV**	**40.2 MW**	**40.5 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A2	**13.14 kV**	**61.2 MW**	**-27.5 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**0.457 kV**	**0.143 MW**	**0.143 Mvar**	Unit Auxiliary Transformer
Identify calculated values, if any:				
F2	**234.2 kV**	**59.9 MW**	**-36.6 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A2	**15.0 kV**	**60.6 MW**	**45.5 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**0.522 kV**	**0.227 MW**	**0.173 Mvar**	Unit Auxiliary Transformer
Identify calculated values, if any: B=B1 + B2 + B3				
F2	**243.3 kV**	**60.0 MW**	**35.7 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-32.6	
GSU Reactive Power (Mvar)	-6.0	
Net Leading Reactive Power Capability (Mvar)	-38.5	
Gross Lagging Reactive Power Capability (Mvar)	46.5	
GSU Lagging Reactive Power (Mvar)	-9.7	
Net Lagging Reactive Power Capability (Mvar)	35.7	
Gross Real Power Capability Minimum Stable Load (MW)	39.9	
Gross Real Power Capability Maximum output (MW)	61.2	
Station Service Reactive Load (Mvar)	0.173	
Station Service Real Load (MW)	0.227	
Net Unit Maximum Real Power Output (MW)	60.0	
GSU Real Power Losses (MW)	1.10	
GSU Reactive Losses (Mvar)	-9.4	

Summary of Verification

- Date of Verification: 07/20/2016
- Verification Start Time: 12:20
- Verification End Time: 14:56
- Scheduled Voltage: 230 kV
- Transformer Voltage Ratio:
  - GSU: 16.667
  - Station Service: 29.469
  - Cranking Motor: 3.389
- Transformer Tap Setting:
  - GSU: 3
  - Station Service: 2
  - Cranking Motor: 2

- Ambient conditions at the end of the verification:
    - Air temperature: 96.7 ^{o}F
    - Humidity: 18 %

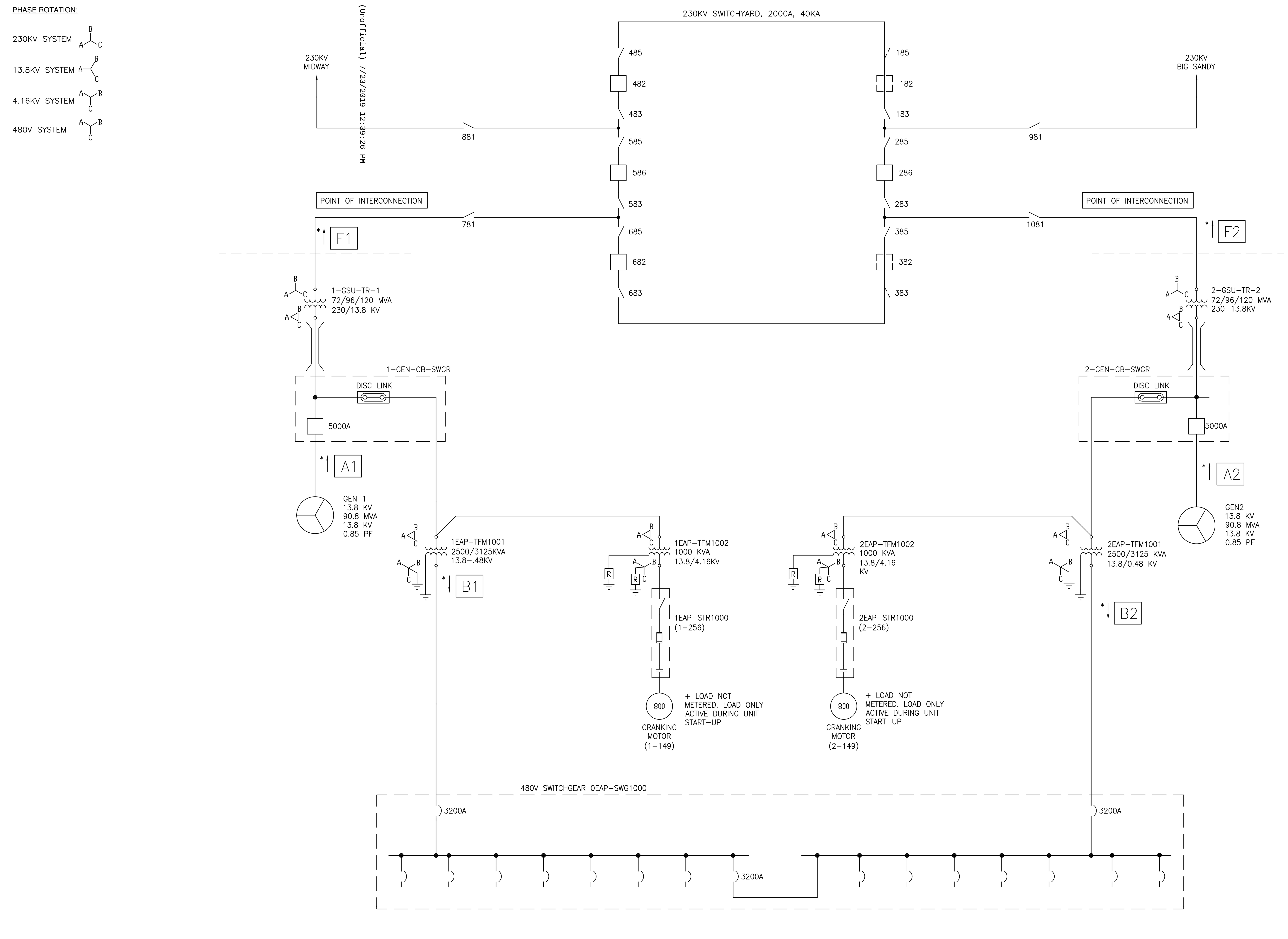
Date that data shown in last verification column in table above was taken: 06/20/2016

Remarks :

UEL and OEL was reached for all testing.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

Appendix A



NOTE:

* POSITIVE NUMBERS INDICATE POWER FLOW IN DIRECTION OF ARROW, NEGATIVE NUMBERS INDICATE POWER FLOW IN OPPOSITE DIRECTION OF ARROW.

NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	REFERENCE DWG'S
																				-	-	-	-	-	-

TRI-STATE
Generation and Transmission Association, Inc.

VENDOR NAME .
VENDOR DWG. NUMBER .
CONTRACT NUMBER .
ORDER NUMBER .

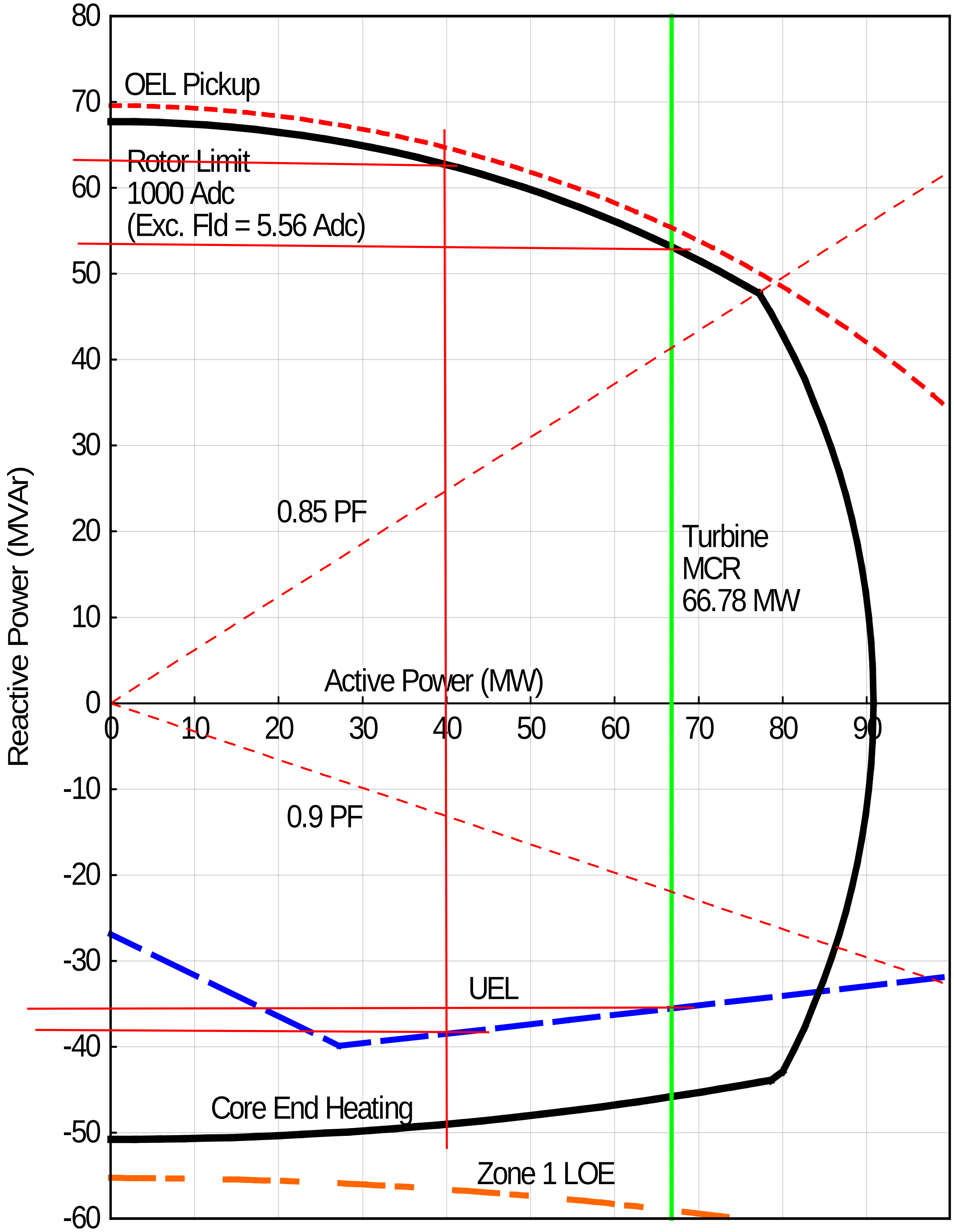
LIMON GENERATING STATION SIMPLIFIED ONE-LINE DIAGRAM FOR NERC STANDARD MOD-025-2

DWN.	BARBARA HERRERA	SCALE	NTS	DWG. NO.	SHEET	REV.
CH'K'D'	DAVE READIO	DATE	08-06-15	0070-064-02-0008	1	0
APPR.	.					

MERIDIAN

(A) 08-06-15 (BJH)

B2 Unofficial Calculated Capability Curve



Testing Data
Tri-State Generation and Transmission Association
Limon Generating Station

At minimum stable load and maximum lagging power factor (Min MW, Max Voltage):

Date: (MM/DD/YY) 06/19/16 **UNIT #** 1

Time at start of Test (HH:MM): 14:46

Air Temperature at start: 93.4 **(°F)**

Humidity at start: 22 **%**

Time at end of Test (HH:MM): 14:55

Air Temperature at end: 93.4 **(°F)**

Humidity at end: 22 **%**

Stator Temperature: 162 **(°F)**

Real Output of Generator: 40.2 **(MW)**

Maximum lagging Reactive power output of Generator: 43.9 **(Mvar)**

Low Side (Generator Bus) Voltage: 15.0 **(kV)**

Net Real power output of station: 40.5 **(MW)**

Net Reactive power output of station: 38.0 **(Mvar)**

High Side GSU (System) Voltage: 242.1 **(kV)**

Station Service Transformer Real power load: 0.331 **(MW)**

Station Service Transformer Reactive power load: 0.384 **(Mvar)**

Station Service Transformer low-side (480 V bus) Voltage: 522 **(V)**

Unit remained on-line?: ☒ - **YES,** ☐ - **NO**

Testing Data
Tri-State Generation and Transmission Association
Limon Generating Station

At minimum stable load and maximum leading power factor (Min MW, Min Voltage):

Date: (MM/DD/YY) 06/16/16 **UNIT #** 1

Time at start of Test (HH:MM): 14:23

Air Temperature at start: 93.1 **(°F)**

Humidity at start: 22 **%**

Time at end of Test (HH:MM): 14:41

Air Temperature at end: 93.4 **(°F)**

Humidity at end: 22 **%**

Stator Temperature: 180 **(°F)**

Real Output of Generator: 39.5 **(MW)**

Maximum leading Reactive power output of Generator: -32.1 **(Mvar)**

Low Side (Generator Bus) Voltage: 12.92 **(kV)**

Net Real power output of station: 38.5 **(MW)**

Net Reactive output of station: -39.5 **(Mvar)**

High Side (System) Voltage: 233.3 **(kV)**

Station Service Transformer Real power load: 0.318 **(MW)**

Station Service Transformer Reactive power load: 0.271 **(Mvar)**

Station Service Transformer low-side (480 V bus) Voltage: 449 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Limon Generating Station

At maximum real output and maximum leading power factor (Max MW, Min Voltage):

Date: (MM/DD/YY) 06/19/16 **UNIT#** 1

Time at start of Test (HH:MM): 12:02

Air Temperature at start: 92.3 **(°F)**

Humidity at start: 25 **%**

Time at end of Test (HH:MM): 13:03

Air Temperature at end: 92.8 **(°F)**

Humidity at end: 24 **%**

Stator Temperature: 164 **(°F)**

Real Output of Generator: 66.3 **(MW)**

Maximum leading Reactive power output of Generator: -23.7 **(Mvar)**

Low Side (Generator Bus) Voltage: 13.1 **(kV)**

Net Real power output of station: 68.3 **(MW)**

Net Reactive output of station: -21.9 **(Mvar)**

High Side (System) Voltage: 233.0 **(kV)**

Service Transformer Real power load: 0.334 **(MW)**

Station Service Transformer Reactive power load: 0.255 **(Mvar)**

Station Service Transformer low-side voltage—480 V Bus: 456 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Limon Generating Station

At maximum real output and maximum lagging power factor (Max MW, Max Voltage):

Date: (MM/DD/YY) 06/19/16 **UNIT #** 1

Time at start of Test (HH:MM): 13:10

Air Temperature at start: 92.8 **(^{o}F)**

Humidity at start: 24 **%**

Time at end of Test (HH:MM): 14:12

Air Temperature at end: 93.6 **(^{o}F)**

Humidity at end: 21 **%**

Stator Temperature at start: 164 **(^{o}F)**

Stator Temperature at end: 188 **(^{o}F)**

Real Output of Generator: 66.1 **(MW)**

Maximum lagging Reactive power output of Generator: 45.5 **(Mvar)**

Low Side (Generator Bus) Voltage: 14.9 **(kV)**

Net Real power output of station: 66.9 **(MW)**

Net Reactive output of station: 35.2 **(Mvar)**

High Side (System) Voltage: 241.5 **(kV)**

Station Service Transformer Real power load: 0.356 **(MW)**

Station Service Transformer Reactive power load: 0.400 **(Mvar)**

Station Service Transformer low-side voltage—480 V Bus: 522 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Limon Generating Station

At minimum stable load and maximum lagging power factor (Min MW, Max Voltage):

Date: (MM/DD/YY) 06/20/16 **UNIT #** 2

Time at start of Test (HH:MM): 14:27

Air Temperature at start: 96.5 **(°F)**

Humidity at start: 20 **%**

Time at end of Test (HH:MM): 14:56

Air Temperature at end: 96.7 **(°F)**

Humidity at end: 18 **%**

Stator Temperature: 167 **(°F)**

Real Output of Generator: 40.0 **(MW)**

Maximum lagging Reactive power output of Generator: 46.5 **(Mvar)**

Low Side (Generator Bus) Voltage: 15.0 **(kV)**

Net Real power output of station: 40.2 **(MW)**

Net Reactive power output of station: 40.5 **(Mvar)**

High Side GSU (System) Voltage: 243.6 **(kV)**

Station Service Transformer Real power load: 0.222 **(MW)**

Station Service Transformer Reactive power load: 0.159 **(Mvar)**

Station Service Transformer low-side (480 V bus) Voltage: 522 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Limon Generating Station

At minimum stable load and maximum leading power factor (Min MW, Min Voltage):

Date: (MM/DD/YY) 06/20/16 **UNIT #** 2

Time at start of Test (HH:MM): 14:12

Air Temperature at start: 96.5 **(^{o}F)**

Humidity at start: 20 **%**

Time at end of Test (HH:MM): 14:25

Air Temperature at end: 96.5 **(^{o}F)**

Humidity at end: 20 **%**

Stator Temperature: 160 **(^{o}F)**

Real Output of Generator: 39.9 **(MW)**

Maximum leading Reactive power output of Generator: -32.6 **(Mvar)**

Low Side (Generator Bus) Voltage: 12.98 **(kV)**

Net Real power output of station: 38.3 **(MW)**

Net Reactive output of station: -38.5 **(Mvar)**

High Side (System) Voltage: 233..3 **(kV)**

Station Service Transformer Real power load: 0.133 **(MW)**

Station Service Transformer Reactive power load: 0.169 **(Mvar)**

Station Service Transformer low-side (480 V bus) Voltage: 451 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Limon Generating Station

At maximum real output and maximum leading power factor (Max MW, Min Voltage):

Date: (MM/DD/YY) 06/20/16 **UNIT#** 2

Time at start of Test (HH:MM): 12:20

Air Temperature at start: 94.2 **(^oF)**

Humidity at start: 22 **%**

Time at end of Test (HH:MM): 12:31

Air Temperature at end: 94.2 **(^oF)**

Humidity at end: 22 **%**

Stator Temperature: 147 **(^oF)**

Real Output of Generator: 61.2 **(MW)**

Maximum leading Reactive power output of Generator: -27.5 **(Mvar)**

Low Side (Generator Bus) Voltage: 13.14 **(kV)**

Net Real power output of station: 59.9 **(MW)**

Net Reactive output of station: -36.6 **(Mvar)**

High Side (System) Voltage: 234.2 **(kV)**

Service Transformer Real power load: 0.143 **(MW)**

Station Service Transformer Reactive power load: 0.143 **(Mvar)**

Station Service Transformer low-side voltage—480 V Bus: 457 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Limon Generating Station

At maximum real output and maximum lagging power factor (Max MW, Max Voltage):

Date: (MM/DD/YY) 06/20/16 **UNIT #** 2

Time at start of Test (HH:MM): 12:35

Air Temperature at start: 94.2 **(^{o}F)**

Humidity at start: 22 **%**

Time at end of Test (HH:MM): 13:46

Air Temperature at end: 95 **(^{o}F)**

Humidity at end: 20 **%**

Stator Temperature at start: 147 **(^{o}F)**

Stator Temperature at end: 187 **(^{o}F)**

Real Output of Generator: 60.8 **(MW)**

Maximum lagging Reactive power output of Generator: 45.2 **(Mvar)**

Low Side (Generator Bus) Voltage: 15.0 **(kV)**

Net Real power output of station: 60.0 **(MW)**

Net Reactive output of station: 35.7 **(Mvar)**

High Side (System) Voltage: 343.3 **(kV)**

Station Service Transformer Real power load: 0.227 **(MW)**

Station Service Transformer Reactive power load: 0.173 **(Mvar)**

Station Service Transformer low-side voltage—480 V Bus: 521.7 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Exhibit No. TS-023

Pyramid Units 1-4

MOD-025 Test Reports and Capability Curves

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

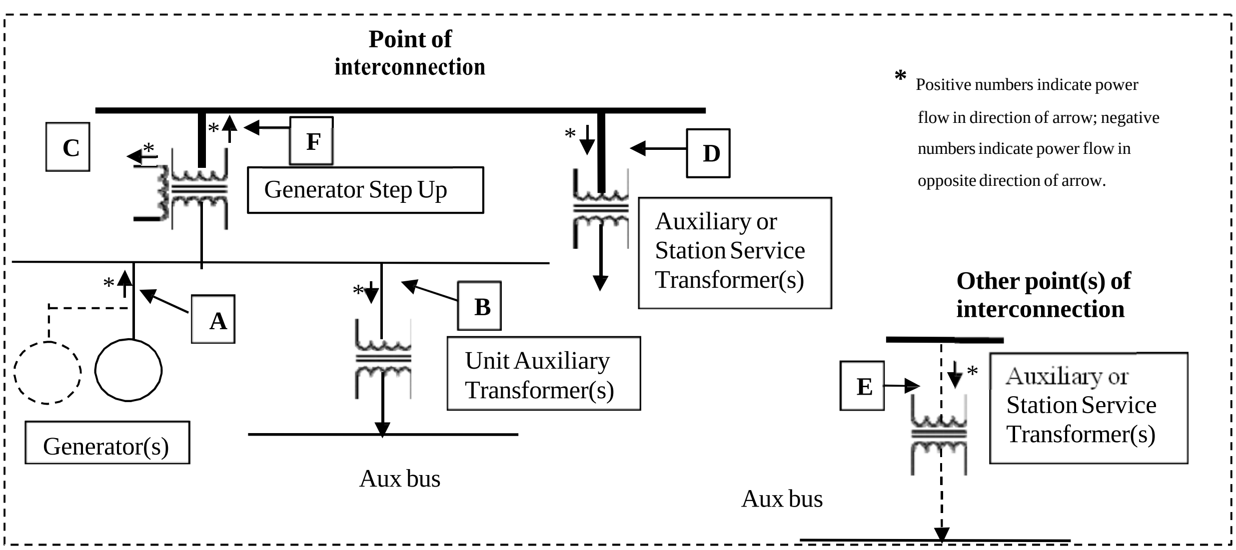
Company: Tri-State Generation and Transmission Association, Inc. **Reported By (name): David Readio**

Plant: Pyramid Generation Station **Unit No.: #1** **Date of Report: 06/24/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A1	**13.1 kV**	**19.97 MW**	**-19.5 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**13.1 kV**	**0.246 MW**	**0.165 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F1	**118.2 kV**	**16.2 MW**	**-18.6 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A1	**14.7 kV**	**20.0 MW**	**35.6 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**14.7 kV**	**0.250 MW**	**0.223 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F1	**123.0 kV**	**16.3 MW**	**26.8 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW Output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A1	**13.0 kV**	**36.2 MW**	**-17.0 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**13.0 kV**	**0.269 MW**	**0.173 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F1	**120.0 kV**	**27.4 MW**	**-21.0 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW Output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A1	**14.7 kV**	**36.6 MW**	**35.6 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**14.7 kV**	**0.277 MW**	**0.231 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F1	**123.0 kV**	**27.8 MW**	**26.8 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-19.5	
GSU Reactive Power (Mvar)	-0.9	
Net Leading Reactive Power Capability (Mvar)	-18.6	
Gross Lagging Reactive Power Capability (Mvar)	35.60	
GSU Lagging Reactive Power (Mvar)	8.80	
Net Lagging Reactive Power Capability (Mvar)	26.80	
Gross Real Power Capability Minimum Stable Load (MW)	20.0	
Gross Real Power Capability Maximum output (MW)	36.6	
Station Service Reactive Load (Mvar)	0.231	
Station Service Real Load (MW)	0.277	
Net Unit Maximum Real Power Output (MW)	27.8	
GSU Real Power Losses (MW)	8.52	
GSU Reactive Losses (Mvar)	-8.8	

Summary of Verification

- Date of Verification 06/22/2016; Verification Start Time 1245 , Verification End Time 1426
- Scheduled Voltage 120 kV
- Transformer Voltage Ratio: GSU 8.54 , Station Aux 28.75 ,
- Transformer Tap Setting: GSU 2 , Station Aux 3 ,
- Ambient conditions at the end of the verification period:

  Air temperature: 99^{o}F

  Humidity: 14%

  Cooling water temperature: N/A

  Other data as applicable: __________

- Generator hydrogen pressure at time of test (if applicable) N/A

Date that data shown in last verification column in table above was taken 06/22/2016

Remarks :

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

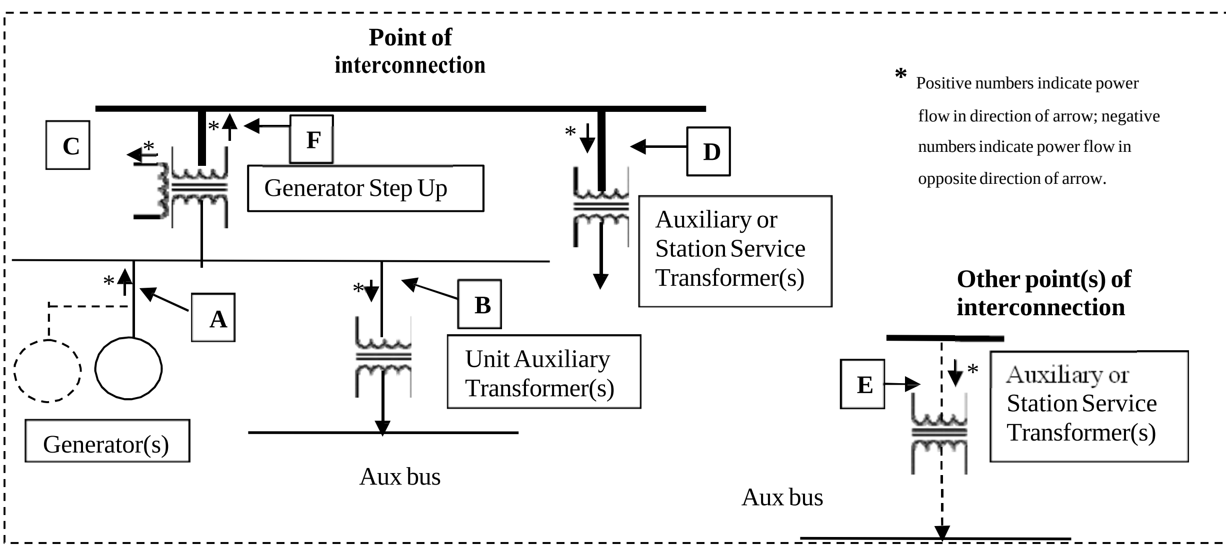
Company: Tri-State Generation and Transmission Association, Inc. **Reported By (name): David Readio**

Plant: Pyramid Generation Station **Unit No.: #2** **Date of Report: 06/24/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A2	**13.1 kV**	**20.0 MW**	**-12.9 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**13.1 kV**	**0.244 MW**	**0.162 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F1	**117.8 kV**	**16.33 MW**	**-13.8 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A2	**14.7 kV**	**20.1 MW**	**41.9 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**14.7 kV**	**0.241 MW**	**0.214 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F1	**122.2 kV**	**16.25 MW**	**33.09 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW Output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A2	**13.1 kV**	**40.1 MW**	**-14.8 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**13.1 kV**	**0.265 MW**	**0.265 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F1	**117.2 kV**	**33.0 MW**	**-14.7 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW Output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A2	**14.7 kV**	**40.0 MW**	**38.8 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B1	**14.7 kV**	**0.272 MW**	**0.236 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F1	**123.0 kV**	**33.0 MW**	**29.57 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-14.80	
GSU Reactive Power (Mvar)	0.10	
Net Leading Reactive Power Capability (Mvar)	-14.70	
Gross Lagging Reactive Power Capability (Mvar)	41.90	
GSU Lagging Reactive Power (Mvar)	8.81	
Net Lagging Reactive Power Capability (Mvar)	33.09	
Gross Real Power Capability Minimum Stable Load (MW)	20.00	
Gross Real Power Capability Maximum output (MW)	40.10	
Station Service Reactive Load (Mvar)	0.272	
Station Service Real Load (MW)	0.236	
Net Unit Maximum Real Power Output (MW)	33.00	
GSU Real Power Losses (MW)	-6.86	
GSU Reactive Losses (Mvar)	-8.54	

Summary of Verification

- Date of Verification 06/23/2016; Verification Start Time 1840, Verification End Time 2032
- Scheduled Voltage 120 kV
- Transformer Voltage Ratio: GSU 8.54, Station Aux 28.75,
- Transformer Tap Setting: GSU 2, Station Aux 3,
- Ambient conditions at the end of the verification period:

  Air temperature: 89°F

  Humidity: 20%

  Cooling water temperature: N/A

  Other data as applicable: __________
- Generator hydrogen pressure at time of test (if applicable) N/A

Date that data shown in last verification column in table above was taken: 06/23/2016

Remarks :

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

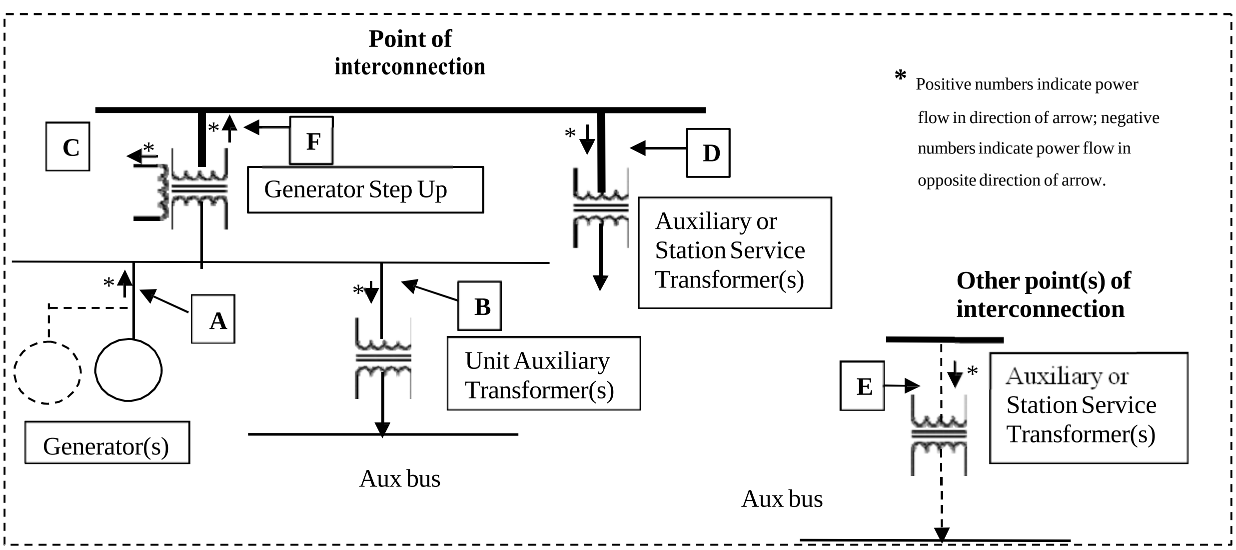
Company: Tri-State Generation and Transmission Association, Inc. **Reported By (name): David Readio**

Plant: Pyramid Generation Station **Unit No.: #3** **Date of Report: 06/22/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A3	**13.1 kV**	**20.0 MW**	**-18.3 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**13.1 kV**	**0.223 MW**	**0.143 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F2	**117.8 kV**	**16.28 MW**	**-16.6 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A3	**14.7 kV**	**20.0 MW**	**36.6 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**14.7 kV**	**0.237 MW**	**0.196 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F2	**123.3 kV**	**16.18 MW**	**28.42 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW Output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A3	**13.2 kV**	**39.6 MW**	**-17.1 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**13.2 kV**	**0.250 MW**	**0.152 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F2	**118.1 kV**	**32.5 MW**	**-16.7 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW Output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A3	**14.7 kV**	**39.5 MW**	**37.8 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**14.7 kV**	**0.250 MW**	**0.203 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F2	**123.2 kV**	**32.35 MW**	**28.65 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-18.3	
GSU Reactive Power (Mvar)	-1.7	
Net Leading Reactive Power Capability (Mvar)	-16.6	
Gross Lagging Reactive Power Capability (Mvar)	37.8	
GSU Lagging Reactive Power (Mvar)	9.15	
Net Lagging Reactive Power Capability (Mvar)	28.65	
Gross Real Power Capability Minimum Stable Load (MW)	20.0	
Gross Real Power Capability Maximum output (MW)	39.6	
Station Service Reactive Load (Mvar)	0.203	
Station Service Real Load (MW)	0.250	
Net Unit Maximum Real Power Output (MW)	32.50	
GSU Real Power Losses (MW)	-6.85	
GSU Reactive Losses (Mvar)	-9.15	

Summary of Verification

- Date of Verification 06/23/2016; Verification Start Time 2000, Verification End Time 2143
- Scheduled Voltage 120 kV
- Transformer Voltage Ratio: GSU 8.54, Station Aux 28.75,
- Transformer Tap Setting: GSU 2, Station Aux 3,
- Ambient conditions at the end of the verification period:

  Air temperature: 88°F

  Humidity: 25%

  Cooling water temperature: N/A

  Other data as applicable: __________

- Generator hydrogen pressure at time of test (if applicable) N/A

Date that data shown in last verification column in table above was taken: 06/22/2016

Remarks :

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

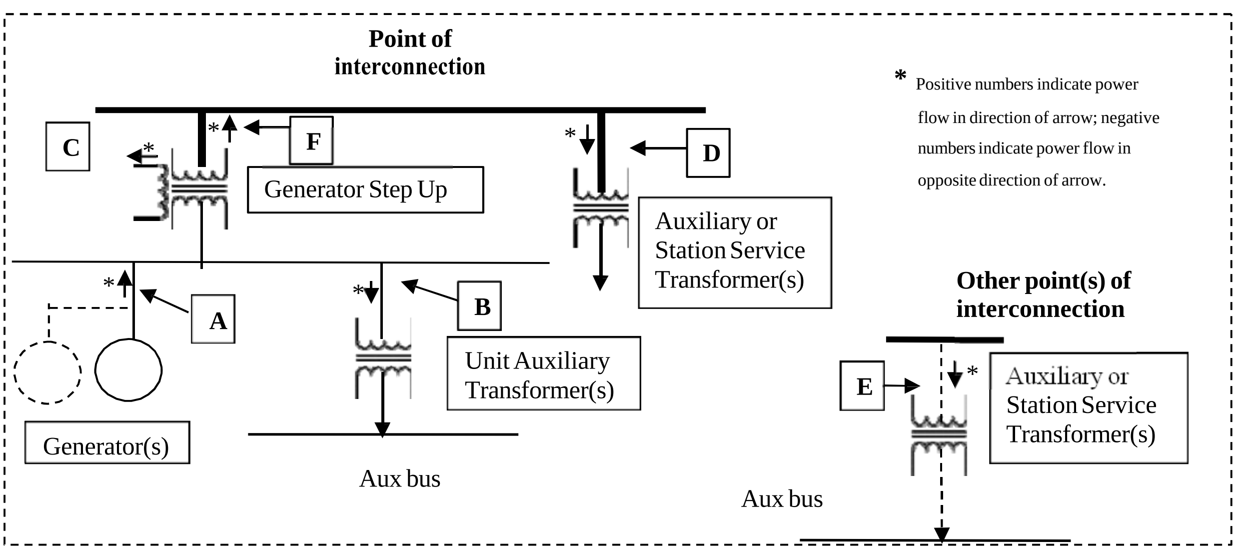
Company: Tri-State Generation and Transmission Association, Inc. **Reported By (name): David Readio**

Plant: Pyramid Generation Station **Unit No.: #4** **Date of Report: 06/23/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A4	**13.2 kV**	**20.0 MW**	**-20.2 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**13.2 kV**	**0.220 MW**	**0.146 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F2	**118.4 kV**	**16.2 MW**	**-17.7 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A4	**14.7 kV**	**20.0 MW**	**40.38 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**14.7 kV**	**0.225 MW**	**0.194 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F2	**122.6 kV**	**16.29 MW**	**31.61 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW Output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A4	**13.3 kV**	**38.9 MW**	**-17.65 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**13.2 kV**	**0.240 MW**	**0.164 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F2	**118.9 kV**	**31.9 MW**	**-16.9 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW Output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A4	**14.7 kV**	**37.4 MW**	**39.0 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B2	**14.7 kV**	**0.247 MW**	**0.205 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
F2	**123.0 kV**	**30.40 MW**	**29.84 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-20.2	
GSU Reactive Power (Mvar)	-2.3	
Net Leading Reactive Power Capability (Mvar)	-17.7	
Gross Lagging Reactive Power Capability (Mvar)	40.38	
GSU Lagging Reactive Power (Mvar)	8.77	
Net Lagging Reactive Power Capability (Mvar)	31.61	
Gross Real Power Capability Minimum Stable Load (MW)	20.0	
Gross Real Power Capability Maximum output (MW)	38.9	
Station Service Reactive Load (Mvar)	0.247	
Station Service Real Load (MW)	0.205	
Net Unit Maximum Real Power Output (MW)	31.9	
GSU Real Power Losses (MW)	6.75	
GSU Reactive Losses (Mvar)	-9.16	

Summary of Verification

- Date of Verification 06/23/2016; Verification Start Time 1355, Verification End Time 1514
- Scheduled Voltage 120 kV
- Transformer Voltage Ratio: GSU 8.54, Station Aux 28.75,
- Transformer Tap Setting: GSU 2, Station Aux 3,
- Ambient conditions at the end of the verification period:

  Air temperature: 88°F

  Humidity: 25%

  Cooling water temperature: N/A

  Other data as applicable: __________

- Generator hydrogen pressure at time of test (if applicable) N/A

Date that data shown in last verification column in table above was taken: 06/23/2016

Remarks :

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

Appendix A

NOTES:
1. REVENUE METERING PROVIDED BY TRI-STATE AND LOCATED IN SWITCH YARD. PROVISIONS FOR ADDITIONAL METERING ARE LOCATED IN 15KV SWITCHGEAR.
2. NUMBERS IN PARENTHESES ARE TRI-STATE SWITCHYARD IDENTIFIERS. SEE TRI-STATE DRAWING 53060-B1-001.

NOTE:

* POSITIVE NUMBERS INDICATE POWER FLOW IN DIRECTION OF ARROW, NEGATIVE NUMBERS INDICATE POWER FLOW IN OPPOSITE DIRECTION OF ARROW.

TRI-STATE
Generation and Transmission Association, Inc.

PYRAMID GENERATING STATION
SIMPLIFIED ONE-LINE DIAGRAM
FOR NERC STANDARD MOD-025-2

VENDOR NAME	.	DWN.	BARBARA HERRERA
VENDOR DWG. NUMBER	.	CH'K'D'	DAVE READIO
CONTRACT NUMBER	.	APPR.	.
ORDER NUMBER	.		

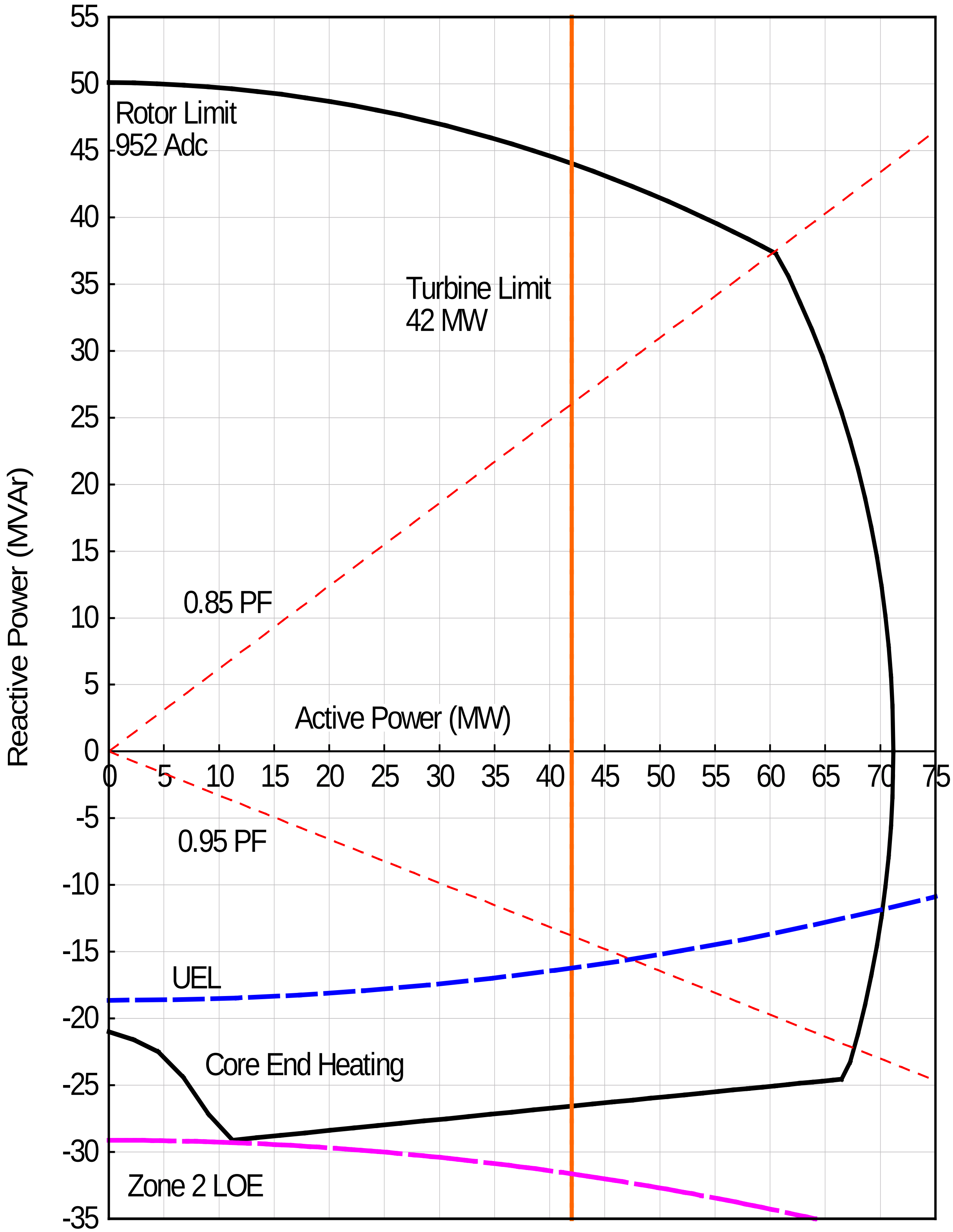
SCALE NTS; DATE 08-06-15; DWG. NO. 0072-064-02-0031; SHEET 1; REV. 0

NO. | DATE | REVISION | DWN. | CHK'D | REFERENCE DWG'S

MERIDIAN

(A) 08-06-15 (BJH)

B2 Calculated Generator Capability Curve



Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At minimum stable load and maximum lagging power factor (Min MW, Max Voltage):

Date: (MM/DD/YY) 06/22/2016 **UNIT #** 1

Time at start of Test (HH:MM): 14:10

Air Temperature at start: 97 **(°F)**

Humidity at start: 15 **%**

Time at end of Test (HH:MM): 14:20

Air Temperature at end: 97 **(°F)**

Humidity at end: 15 **%**

Stator Temperature: 182 **(°F)**

Real Output of Generator: 20.0 **(MW)**

Maximum lagging Reactive power output of Generator: 35.6 **(Mvar)**

Low Side (Generator Bus) Voltage: 14.7 **(kV)**

Net Real power output of station: 19.5 **(MW)**

Net Reactive power output of station: 26.8 **(Mvar)**

High Side GSU (System) Voltage: 123.0 **(kV)**

Station Service Transformer Real power load: 0.250 **(MW)**

Station Service Transformer Reactive power load: 0.223 **(Mvar)**

Station Service Transformer low-side (480 V bus) Voltage: 511 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At minimum stable load and maximum leading power factor (Min MW, Min Voltage):

Date: (MM/DD/YY) 06/22/2016 **UNIT #** 1

Time at start of Test (HH:MM): 14:20

Air Temperature at start: 97 **(°F)**

Humidity at start: 15 **%**

Time at end of Test (HH:MM): 14:26

Air Temperature at end: 99 **(°F)**

Humidity at end: 14 **%**

Stator Temperature: 182 **(°F)**

Real Output of Generator: 19.97 **(MW)**

Maximum leading Reactive power output of Generator: -19.5 **(Mvar)**

Low Side (Generator Bus) Voltage: 13.1 **(kV)**

Net Real power output of station: 19.6 **(MW)**

Net Reactive output of station: -21.0 **(Mvar)**

High Side (System) Voltage: 118.2 **(kV)**

Station Service Transformer Real power load: 0.246 **(MW)**

Station Service Transformer Reactive power load: 0.165 **(Mvar)**

Station Service Transformer low-side (480 V bus) Voltage: 456 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At maximum real output and maximum leading power factor (Max MW, Min Voltage):

Date: (MM/DD/YY) 06/22/2016 **UNIT#** 1

Time at start of Test (HH:MM): 13:50

Air Temperature at start: 97 **(°F)**

Humidity at start: 15 **%**

Time at end of Test (HH:MM): 14:05

Air Temperature at end: 97 **(°F)**

Humidity at end: 15 **%**

Stator Temperature: 199 **(°F)**

Real Output of Generator: 36.2 **(MW)**

Maximum leading Reactive power output of Generator: -17.0 **(Mvar)**

Low Side (Generator Bus) Voltage: 13.0 **(kV)**

Net Real power output of station: 35.8 **(MW)**

Net Reactive output of station: -21.0 **(Mvar)**

High Side (System) Voltage: 120.0 **(kV)**

Service Transformer Real power load: 0.269 **(MW)**

Station Service Transformer Reactive power load: 0.173 **(Mvar)**

Station Service Transformer low-side voltage—480 V Bus: 456 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At maximum real output and maximum lagging power factor (Max MW, Max Voltage):

Date: (MM/DD/YY) 06/22/2016 **UNIT #** 1

Time at start of Test (HH:MM): 12:45

Air Temperature at start: 97 **(°F)**

Humidity at start: 15 **%**

Time at end of Test (HH:MM): 13:50

Air Temperature at end: 97 **(°F)**

Humidity at end: 15 **%**

Stator Temperature at start: 178 **(°F)**

Stator Temperature at end: 210 **(°F)**

Real Output of Generator: 36.6 **(MW)**

Maximum lagging Reactive power output of Generator: 35.6 **(Mvar)**

Low Side (Generator Bus) Voltage: 14.7 **(kV)**

Net Real power output of station: 35.2 **(MW)**

Net Reactive output of station: 33.2 **(Mvar)**

High Side (System) Voltage: 123.0 **(kV)**

Station Service Transformer Real power load: 0.277 **(MW)**

Station Service Transformer Reactive power load: 0.231 **(Mvar)**

Station Service Transformer low-side voltage—480 V Bus: 509 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At minimum stable load and maximum lagging power factor (Min MW, Max Voltage):

Date: (MM/DD/YY) 06/23/2016 **UNIT #** 2

Time at start of Test (HH:MM): 20:12

Air Temperature at start: 90 **(°F)**

Humidity at start: 20 **%**

Time at end of Test (HH:MM): 20:20

Air Temperature at end: 89 **(°F)**

Humidity at end: 20 **%**

Stator Temperature: 182 **(°F)**

Real Output of Generator: 20.1 **(MW)**

Maximum lagging Reactive power output of Generator: 41.9 **(Mvar)**

Low Side (Generator Bus) Voltage: 14.7 **(kV)**

Net Real power output of station: 16.25 **(MW)**

Net Reactive power output of station: 33.09 **(Mvar)**

High Side GSU (System) Voltage: 122.2 **(kV)**

Station Service Transformer Real power load: 0.241 **(MW)**

Station Service Transformer Reactive power load: 0.214 **(Mvar)**

Station Service Transformer low-side (480 V bus) Voltage: 512 **(V)**

Unit remained on-line?: ☒ - **YES,** ☐ - **NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At minimum stable load and maximum leading power factor (Min MW, Min Voltage):

Date: (MM/DD/YY) 06/23/2016 **UNIT #** 2

Time at start of Test (HH:MM): 20:23

Air Temperature at start: 89 **(°F)**

Humidity at start: 20 **%**

Time at end of Test (HH:MM): 20:32

Air Temperature at end: 89 **(°F)**

Humidity at end: 20 **%**

Stator Temperature: 182 **(°F)**

Real Output of Generator: 20.0 **(MW)**

Maximum leading Reactive power output of Generator: -12.9 **(Mvar)**

Low Side (Generator Bus) Voltage: 13.1 **(kV)**

Net Real power output of station: 16.33 **(MW)**

Net Reactive output of station: -13.8 **(Mvar)**

High Side (System) Voltage: 117.8 **(kV)**

Station Service Transformer Real power load: 0.244 **(MW)**

Station Service Transformer Reactive power load: 0.162 **(Mvar)**

Station Service Transformer low-side (480 V bus) Voltage: 456 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At maximum real output and maximum leading power factor (Max MW, Min Voltage):

Date: (MM/DD/YY) 06/23/2016 **UNIT#** 2

Time at start of Test (HH:MM): 19:49

Air Temperature at start: 90 **(°F)**

Humidity at start: 20 **%**

Time at end of Test (HH:MM): 20:00

Air Temperature at end: 90 **(°F)**

Humidity at end: 20 **%**

Stator Temperature: 206 **(°F)**

Real Output of Generator: 40.1 **(MW)**

Maximum leading Reactive power output of Generator: -14.8 **(Mvar)**

Low Side (Generator Bus) Voltage: 13.1 **(kV)**

Net Real power output of station: 33.0 **(MW)**

Net Reactive output of station: -14.7 **(Mvar)**

High Side (System) Voltage: 117.2 **(kV)**

Service Transformer Real power load: 0.265 **(MW)**

Station Service Transformer Reactive power load: 0.265 **(Mvar)**

Station Service Transformer low-side voltage—480 V Bus: 457 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At maximum real output and maximum lagging power factor (Max MW, Max Voltage):

Date: (MM/DD/YY) 06/23/2016 **UNIT #** 2

Time at start of Test (HH:MM): 18:40

Air Temperature at start: 93 **(°F)**

Humidity at start: 20 **%**

Time at end of Test (HH:MM): 19:45

Air Temperature at end: 90 **(°F)**

Humidity at end: 20 **%**

Stator Temperature at start: 176 **(°F)**

Stator Temperature at end: 215 **(°F)**

Real Output of Generator: 40.0 **(MW)**

Maximum lagging Reactive power output of Generator: 38.8 **(Mvar)**

Low Side (Generator Bus) Voltage: 14.7 **(kV)**

Net Real power output of station: 33.0 **(MW)**

Net Reactive output of station: 29.57 **(Mvar)**

High Side (System) Voltage: 123.0 **(kV)**

Station Service Transformer Real power load: 0.272 **(MW)**

Station Service Transformer Reactive power load: 0.236 **(Mvar)**

Station Service Transformer low-side voltage—480 V Bus: 511 **(V)**

Unit remained on-line?: ☒ - **YES,** ☐ - **NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At minimum stable load and maximum lagging power factor (Min MW, Max Voltage):

Date: (MM/DD/YY) 06/22/2016 **UNIT #** 3

Time at start of Test (HH:MM): 21:24

Air Temperature at start: 91 **(°F)**

Humidity at start: 18 **%**

Time at end of Test (HH:MM): 21:30

Air Temperature at end: 88 **(°F)**

Humidity at end: 25 **%**

Stator Temperature: 185 **(°F)**

Real Output of Generator: 20.0 **(MW)**

Maximum lagging Reactive power output of Generator: 36.6 **(Mvar)**

Low Side (Generator Bus) Voltage: 14.7 **(kV)**

Net Real power output of station: 16.18 **(MW)**

Net Reactive power output of station: 28.42 **(Mvar)**

High Side GSU (System) Voltage: 123.3 **(kV)**

Station Service Transformer Real power load: 0.237 **(MW)**

Station Service Transformer Reactive power load: 0.196 **(Mvar)**

Station Service Transformer low-side (480 V bus) Voltage: 510 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At minimum stable load and maximum leading power factor (Min MW, Min Voltage):

Date: (MM/DD/YY) 06/22/2016 **UNIT #** 3

Time at start of Test (HH:MM): 21:30

Air Temperature at start: 88 **(^{o}F)**

Humidity at start: 25 **%**

Time at end of Test (HH:MM): 21:43

Air Temperature at end: 88 **(^{o}F)**

Humidity at end: 25 **%**

Stator Temperature: 179 **(^{o}F)**

Real Output of Generator: 20.0 **(MW)**

Maximum leading Reactive power output of Generator: -18.3 **(Mvar)**

Low Side (Generator Bus) Voltage: 13.1 **(kV)**

Net Real power output of station: 16.28 **(MW)**

Net Reactive output of station: -16.6 **(Mvar)**

High Side (System) Voltage: 117.8 **(kV)**

Station Service Transformer Real power load: 0.223 **(MW)**

Station Service Transformer Reactive power load: 0.143 **(Mvar)**

Station Service Transformer low-side (480 V bus) Voltage: 457 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At maximum real output and maximum leading power factor (Max MW, Min Voltage):

Date: (MM/DD/YY) 06/22/2016 **UNIT#** 3

Time at start of Test (HH:MM): 21:10

Air Temperature at start: 95 **(°F)**

Humidity at start: 13 **%**

Time at end of Test (HH:MM): 21:18

Air Temperature at end: 91 **(°F)**

Humidity at end: 18 **%**

Stator Temperature: 205 **(°F)**

Real Output of Generator: 39.6 **(MW)**

Maximum leading Reactive power output of Generator: -17.1 **(Mvar)**

Low Side (Generator Bus) Voltage: 13.2 **(kV)**

Net Real power output of station: 32.5 **(MW)**

Net Reactive output of station: -16.7 **(Mvar)**

High Side (System) Voltage: 118.1 **(kV)**

Service Transformer Real power load: 0.250 **(MW)**

Station Service Transformer Reactive power load: 0.152 **(Mvar)**

Station Service Transformer low-side voltage—480 V Bus: 458 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At maximum real output and maximum lagging power factor (Max MW, Max Voltage):

Date: (MM/DD/YY) 06/22/2016 **UNIT #** 3

Time at start of Test (HH:MM): 20:00

Air Temperature at start: 97 **(°F)**

Humidity at start: 14 **%**

Time at end of Test (HH:MM): 21:10

Air Temperature at end: 95 **(°F)**

Humidity at end: 13 **%**

Stator Temperature at start: 181 **(°F)**

Stator Temperature at end: 214 **(°F)**

Real Output of Generator: 39.5 **(MW)**

Maximum lagging Reactive power output of Generator: 37.8 **(Mvar)**

Low Side (Generator Bus) Voltage: 14.7 **(kV)**

Net Real power output of station: 32.35 **(MW)**

Net Reactive output of station: 28.65 **(Mvar)**

High Side (System) Voltage: 123.2 **(kV)**

Station Service Transformer Real power load: 0.250 **(MW)**

Station Service Transformer Reactive power load: 0.203 **(Mvar)**

Station Service Transformer low-side voltage—480 V Bus: 510 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At minimum stable load and maximum lagging power factor (Min MW, Max Voltage):

Date: (MM/DD/YY) 06/23/2016 **UNIT #** 4

Time at start of Test (HH:MM): 15:05

Air Temperature at start: 93 **(°F)**

Humidity at start: 25 **%**

Time at end of Test (HH:MM): 15:09

Air Temperature at end: 93 **(°F)**

Humidity at end: 25 **%**

Stator Temperature: 200 **(°F)**

Real Output of Generator: 20.0 **(MW)**

Maximum lagging Reactive power output of Generator: 40.38 **(Mvar)**

Low Side (Generator Bus) Voltage: 14.7 **(kV)**

Net Real power output of station: 16.29 **(MW)**

Net Reactive power output of station: 31.61 **(Mvar)**

High Side GSU (System) Voltage: 122.6 **(kV)**

Station Service Transformer Real power load: 0.225 **(MW)**

Station Service Transformer Reactive power load: 0.194 **(Mvar)**

Station Service Transformer low-side (480 V bus) Voltage: 510 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At minimum stable load and maximum leading power factor (Min MW, Min Voltage):

Date: (MM/DD/YY) 06/23/2016 **UNIT #** 4

Time at start of Test (HH:MM): 15:10

Air Temperature at start: 93 **(°F)**

Humidity at start: 25 **%**

Time at end of Test (HH:MM): 15:14

Air Temperature at end: 95 **(°F)**

Humidity at end: 25 **%**

Stator Temperature: 190 **(°F)**

Real Output of Generator: 20.0 **(MW)**

Maximum leading Reactive power output of Generator: -20.0 **(Mvar)**

Low Side (Generator Bus) Voltage: 13.2 **(kV)**

Net Real power output of station: 16.2 **(MW)**

Net Reactive output of station: -17.7 **(Mvar)**

High Side (System) Voltage: 118.4 **(kV)**

Station Service Transformer Real power load: 0.220 **(MW)**

Station Service Transformer Reactive power load: 0.146 **(Mvar)**

Station Service Transformer low-side (480 V bus) Voltage: 457 **(V)**

Unit remained on-line?: ☒ **– YES,** ☐ **– NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At maximum real output and maximum leading power factor (Max MW, Min Voltage):

Date: (MM/DD/YY) 06/23/2016 **UNIT#** 4

Time at start of Test (HH:MM): 14:57

Air Temperature at start: 93 **(^{o}F)**

Humidity at start: 25 **%**

Time at end of Test (HH:MM): 15:00

Air Temperature at end: 93 **(^{o}F)**

Humidity at end: 25 **%**

Stator Temperature: 213 **(^{o}F)**

Real Output of Generator: 38.9 **(MW)**

Maximum leading Reactive power output of Generator: -17.65 **(Mvar)**

Low Side (Generator Bus) Voltage: 13.3 **(kV)**

Net Real power output of station: 31.9 **(MW)**

Net Reactive output of station: -16.9 **(Mvar)**

High Side (System) Voltage: 118.9 **(kV)**

Service Transformer Real power load: 0.240 **(MW)**

Station Service Transformer Reactive power load: 0.164 **(Mvar)**

Station Service Transformer low-side voltage—480 V Bus: 461 **(V)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
Pyramid Generating Station

At maximum real output and maximum lagging power factor (Max MW, Max Voltage):

Date: (MM/DD/YY) 06/23/2016 **UNIT #** 4

Time at start of Test (HH:MM): 13:55

Air Temperature at start: 88 **(°F)**

Humidity at start: 24 **%**

Time at end of Test (HH:MM): 14:56

Air Temperature at end: 93 **(°F)**

Humidity at end: 25 **%**

Stator Temperature at start: 169 **(°F)**

Stator Temperature at end: 213 **(°F)**

Real Output of Generator: 37.4 **(MW)**

Maximum lagging Reactive power output of Generator: 39.0 **(Mvar)**

Low Side (Generator Bus) Voltage: 14.7 **(kV)**

Net Real power output of station: 30.4 **(MW)**

Net Reactive output of station: 29.84 **(Mvar)**

High Side (System) Voltage: 123.0 **(kV)**

Station Service Transformer Real power load: 0.247 **(MW)**

Station Service Transformer Reactive power load: 0.205 **(Mvar)**

Station Service Transformer low-side voltage—480 V Bus: 510 **(V)**

Unit remained on-line?: ☒ **– YES,** ☐ **– NO**

Exhibit No. TS-023

Schafer Units 1-7

MOD-025 Test Reports and Capability Curves

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

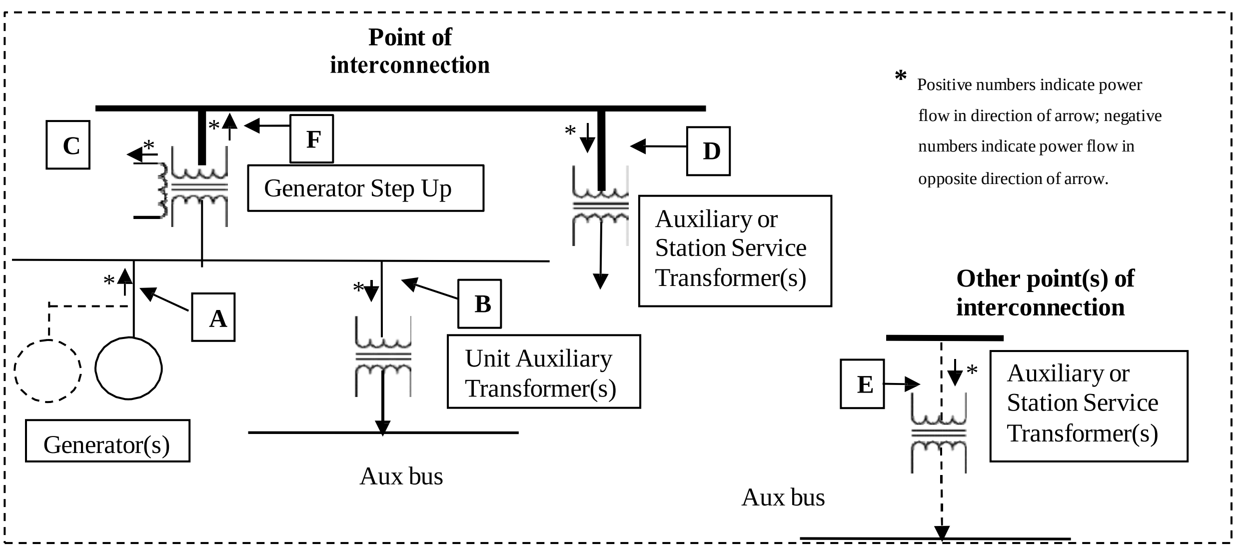
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: JM Shafer Generating Station **Unit: GTA** **Date of Report: 03/14/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**12.43 kV**	**12.0 MW**	**-19.0 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**234.0 kV**	**0.84 MW**	**0.31 Mvar**	Station Service Transformer #1
D2	**234.0 kV**	**1.11 MW**	**0.56 Mvar**	Station Service Transformer #2
D	**234.0 kV**	**1.95 MW**	**0.87 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**234.0 kV**	**11.75 MW**	**-20.58 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**12.427 kV**	**12.2 MW**	**39.60 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**236.0 kV**	**0.84 MW**	**0.33 Mvar**	Station Service Transformer #1
D2	**236.0 kV**	**1.12 MW**	**0.58 Mvar**	Station Service Transformer #2
D	**236.0 kV**	**1.96 MW**	**0.91 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**236.0 kV**	**12.19 MW**	**35.70 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**12.75 kV**	**35.4 MW**	**-16.0 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**234.3 kV**	**1.76 MW**	**0.88 Mvar**	Station Service Transformer #1
D2	**234.3 kV**	**1.45 MW**	**0.72 Mvar**	Station Service Transformer #2
D	**234.3 kV**	**3.21 MW**	**1.60 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**234.3 kV**	**35.10 MW**	**-28.27 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for GTB that was on-line and connected to the same GSU.				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**14.47 kV**	**35.3 MW**	**41.4 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**1.77 MW**	**0.89 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.46 MW**	**0.73 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**3.23 MW**	**1.62 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**35.11 MW**	**33.21 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-16.00	
GSU Reactive Power (Mvar)	-12.27	
Net Leading Reactive Power Capability (Mvar)	-28.27	
Gross Lagging Reactive Power Capability (Mvar)	41.40	
GSU Lagging Reactive Power (Mvar)	8.19	
Net Lagging Reactive Power Capability (Mvar)	33.21	
Gross Real Power Capability Minimum Stable Load (MW)	12.00	
Gross Real Power Capability Maximum output (MW)	35.35	
Station Service Reactive Load (Mvar)	1.60	
Station Service Real Load (MW)	3.21	
Net Unit Maximum Real Power Output (MW)	32.14	
GSU Real Power Losses (MW)	0.21	
GSU Reactive Losses (Mvar)	-6.48	

Summary of Verification

- Date of Verification: 12/15/2015
- Verification Start Time: 12:30
- Verification End Time: 13:30
- Scheduled Voltage: 235 kV
- Transformer Voltage Ratio:
  - GSU: 17.9
  - AMF #1: 55.288
  - AMF#2: 55.288
- Transformer Tap Setting:
  - GSU: 2
  - AMF #1: 3
  - AMF#2: 3

- Ambient conditions at the end of the verification:
    - Air temperature: 27 ºF
    - Humidity: 82%

Date that data shown in last verification column in table above was taken: 12/15/2015

Remarks :

Each unit at JM Shafer was verified separately.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

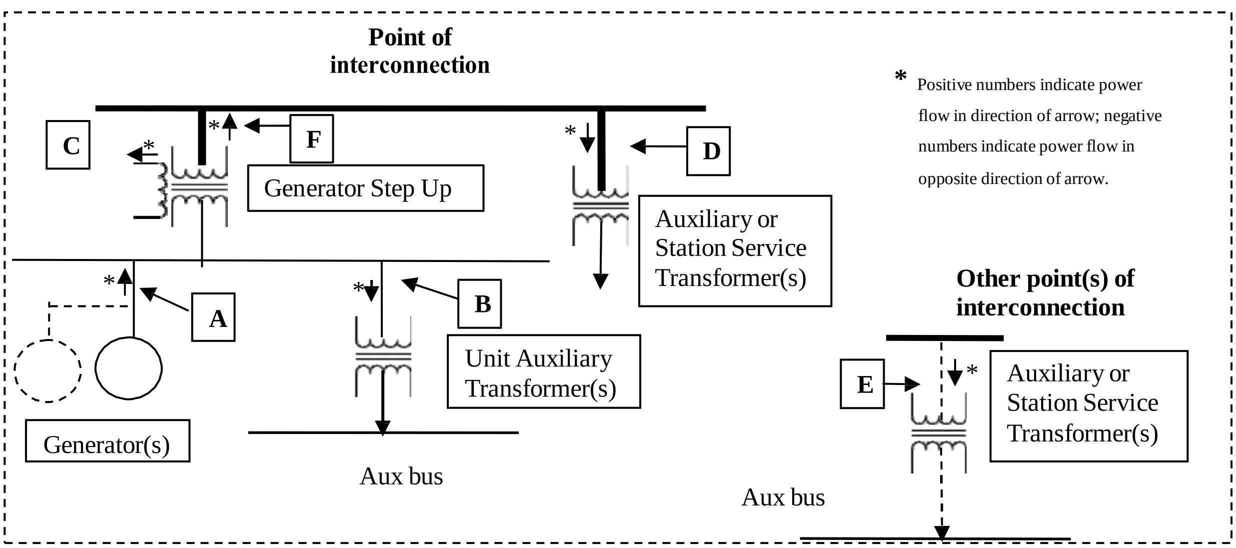
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: JM Shafer Generating Station **Unit: GTB** **Date of Report: 03/14/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**12.43 kV**	**14.6 MW**	**-19.0 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**1.75 MW**	**0.88 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.45 MW**	**0.71 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**3.20 MW**	**1.59 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**13.96 MW**	**-26.50 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for GTA that was on-line and connected to the same GSU.				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**14.52 kV**	**14.0 MW**	**42.21 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**1.76 MW**	**0.88 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.45 MW**	**0.73 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**3.21 MW**	**1.61 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**13.68 MW**	**-26.50 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for GTA that was on-line and connected to the same GSU.				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**12.47 kV**	**35.0 MW**	**-15.90 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**234.9 kV**	**1.77 MW**	**0.88 Mvar**	Station Service Transformer #1
D2	**234.9 kV**	**1.45 MW**	**0.72 Mvar**	Station Service Transformer #2
D	**234.9 kV**	**3.22 MW**	**1.60 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**234.9 kV**	**34.79 MW**	**-24.40 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for GTA that was on-line and connected to the same GSU.				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**14.49 kV**	**35.4 MW**	**43.11 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**1.79 MW**	**0.90 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.47 MW**	**0.73 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**3.26 MW**	**1.63 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**35.11 MW**	**33.21 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for GTA that was on-line and connected to the same GSU.				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-15.90	
GSU Reactive Power (Mvar)	-8.50	
Net Leading Reactive Power Capability (Mvar)	-24.40	
Gross Lagging Reactive Power Capability (Mvar)	43.11	
GSU Lagging Reactive Power (Mvar)	9.65	
Net Lagging Reactive Power Capability (Mvar)	33.46	
Gross Real Power Capability Minimum Stable Load (MW)	14.30	
Gross Real Power Capability Maximum output (MW)	34.90	
Station Service Reactive Load (Mvar)	1.62	
Station Service Real Load (MW)	3.24	
Net Unit Maximum Real Power Output (MW)	31.66	
GSU Real Power Losses (MW)	0.27	
GSU Reactive Losses (Mvar)	-8.64	

Summary of Verification

- Date of Verification: 12/15/2015
- Verification Start Time: 11:15
- Verification End Time: 12:02
- Scheduled Voltage: 235 kV
- Transformer Voltage Ratio:
    - GSU: 17.9
    - AMF #1: 55.288
    - AMF#2: 55.288
- Transformer Tap Setting:
    - GSU: 2
    - AMF #1: 3
    - AMF#2: 3

- Ambient conditions at the end of the verification:
    - Air temperature: __20.3 ºF__
    - Humidity: __90 %__

Date that data shown in last verification column in table above was taken: __12/15/2015__

Remarks :

Each unit at JM Shafer was verified separately.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

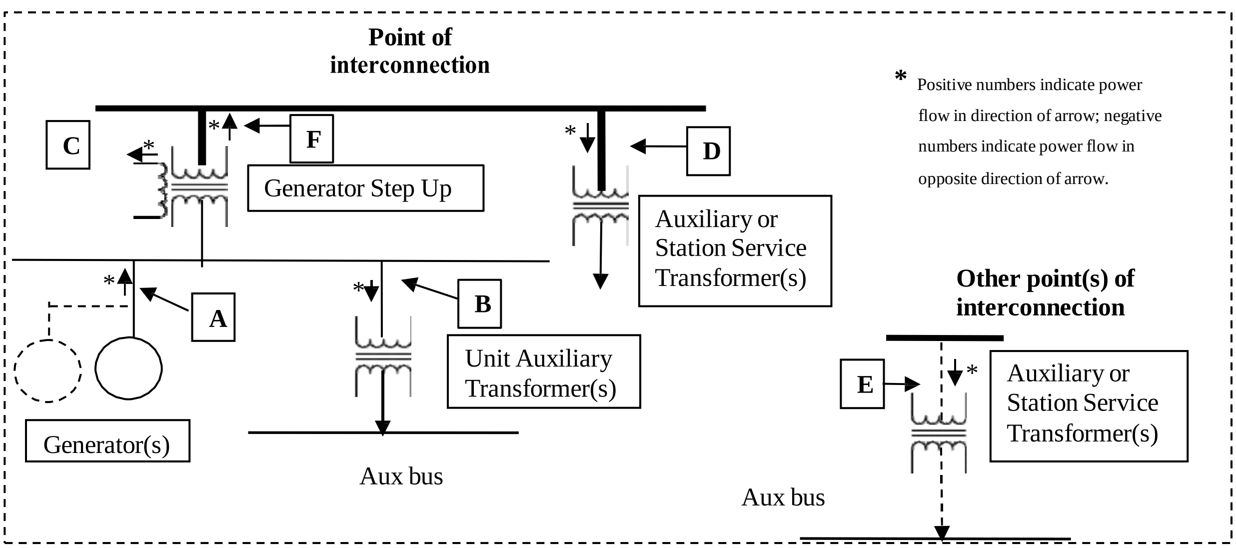
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: JM Shafer Generating Station **Unit: GTC** **Date of Report: 03/14/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**12.43 kV**	**11.75 MW**	**-19.1 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**0.84 MW**	**0.31 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.12 MW**	**0.56 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**1.96 MW**	**0. 87 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**11.72 MW**	**-20.48 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for STB that was on-line and connected to the same GSU.				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**14.48 kV**	**11.80 MW**	**40.49 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**0.84 MW**	**0.32 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.18 MW**	**0.59 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**2.02 MW**	**0.91 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**11.74 MW**	**36.22 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for STB that was on-line and connected to the same GSU.				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**12.47 kV**	**34.90 MW**	**-15.90 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**1.77 MW**	**0.88 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.45 MW**	**0.72 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**3.22 MW**	**1.60 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**234.9 kV**	**34.79 MW**	**-24.40 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for STB that was on-line and connected to the same GSU.				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**14.44 kV**	**35.00 MW**	**41.00 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**1.79 MW**	**0.90 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.47 MW**	**0.73 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**3.26 MW**	**1.63 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**35.11 MW**	**33.21 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for STB that was on-line and connected to the same GSU.				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-15.90	
GSU Reactive Power (Mvar)	-7.35	
Net Leading Reactive Power Capability (Mvar)	-23.25	
Gross Lagging Reactive Power Capability (Mvar)	41.00	
GSU Lagging Reactive Power (Mvar)	8.96	
Net Lagging Reactive Power Capability (Mvar)	32.04	
Gross Real Power Capability Minimum Stable Load (MW)	11.75	
Gross Real Power Capability Maximum output (MW)	34.95	
Station Service Reactive Load (Mvar)	1.62	
Station Service Real Load (MW)	3.22	
Net Unit Maximum Real Power Output (MW)	31.73	
GSU Real Power Losses (MW)	0.36	
GSU Reactive Losses (Mvar)	-5.50	

Summary of Verification

- Date of Verification: 12/14/2015
- Verification Start Time: 09:08
- Verification End Time: 10:02
- Scheduled Voltage: 235 kV
- Transformer Voltage Ratio:
  - GSU: 17.9
  - AMF #1: 55.288
  - AMF#2: 55.288
- Transformer Tap Setting:
  - GSU: 2
  - AMF #1: 3
  - AMF#2: 3

- Ambient conditions at the end of the verification:
  - Air temperature: __22.6 ºF__
  - Humidity: __87 %__

Date that data shown in last verification column in table above was taken: __12/14/2015__

Remarks :

Each unit at JM Shafer was verified separately.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

MOD-025 Attachment 2

<u>One-line Diagram, Table, and Summary for Verification Information Reporting</u>

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

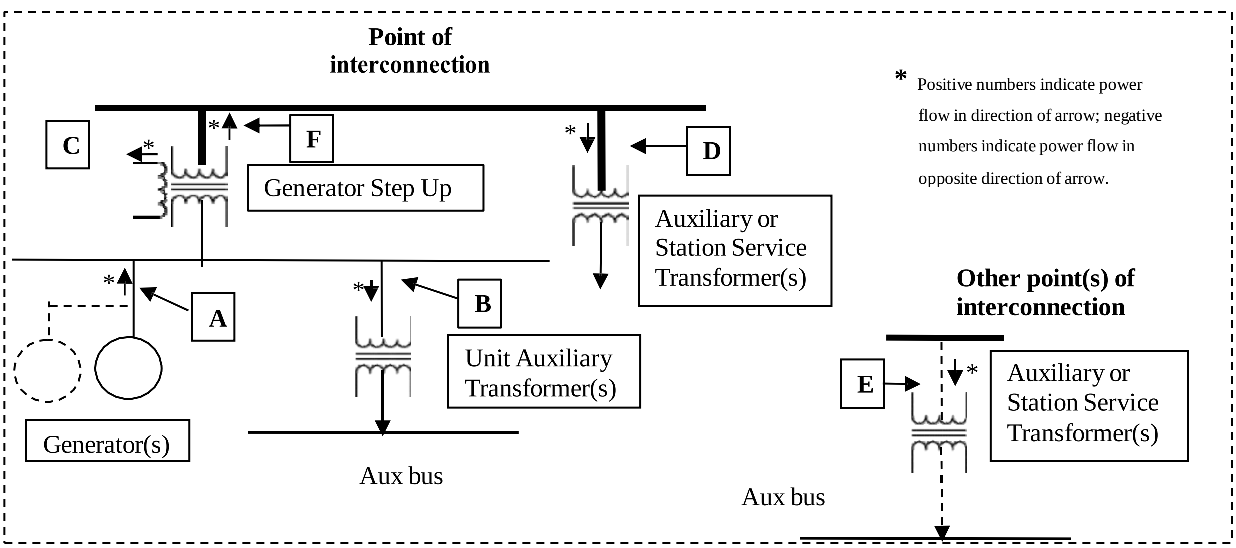
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: JM Shafer Generating Station **Unit: GTD** **Date of Report: 03/14/2016**

<u>Check all that apply:</u>

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**12.39 kV**	**11.90 MW**	**-19.00 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**234.2 kV**	**0.82 MW**	**0.31 Mvar**	Station Service Transformer #1
D2	**234.2 kV**	**1.22 MW**	**0.56 Mvar**	Station Service Transformer #2
D	**234.2 kV**	**2.04 MW**	**0. 87 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**234.2 kV**	**11.56 MW**	**-20.54 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**14.48 kV**	**12.00 MW**	**40.58 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**0.85 MW**	**0.32 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.29 MW**	**0.6 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**2.14 MW**	**0.92 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**11.75 MW**	**36.25 Mvar**	Net unit capability
Identify calculated values, if any				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**12.47 kV**	**35.15 MW**	**-15.70 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**1.76 MW**	**0.88 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.46 MW**	**0.71 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**3.22 MW**	**1.59 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**34.00 MW**	**-28.93 Mvar**	Net unit capability
Identify calculated values, if any: : MW and Mvars adjusted for GTE that was on-line and connected to the same GSU.				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**14.42 kV**	**34.90 MW**	**43.41 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**1.81 MW**	**0.90 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.44 MW**	**0.72 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**3.22 MW**	**1.62 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**33.54 MW**	**27.70 Mvar**	Net unit capability
Identify calculated values, if any: : MW and Mvars adjusted for GTE that was on-line and connected to the same GSU.				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-15.70	
GSU Reactive Power (Mvar)	-13.23	
Net Leading Reactive Power Capability (Mvar)	-28.93	
Gross Lagging Reactive Power Capability (Mvar)	43.41	
GSU Lagging Reactive Power (Mvar)	15.71	
Net Lagging Reactive Power Capability (Mvar)	27.70	
Gross Real Power Capability Minimum Stable Load (MW)	11.95	
Gross Real Power Capability Maximum output (MW)	35.00	
Station Service Reactive Load (Mvar)	1.62	
Station Service Real Load (MW)	3.22	
Net Unit Maximum Real Power Output (MW)	31.78	
GSU Real Power Losses (MW)	2.92	
GSU Reactive Losses (Mvar)	-8.70	

Summary of Verification

- Date of Verification: 12/15/2015
- Verification Start Time: 10:47
- Verification End Time: 11:10
- Scheduled Voltage: 235 kV
- Transformer Voltage Ratio:
  - GSU: 17.9
  - AMF #1: 55.288
  - AMF#2: 55.288
- Transformer Tap Setting:
  - GSU: 2
  - AMF #1: 3
  - AMF#2: 3

- Ambient conditions at the end of the verification:
    - Air temperature: 29.7 °F
    - Humidity: 74 %

Date that data shown in last verification column in table above was taken: 12/15/2015

Remarks :

Each unit at JM Shafer was verified separately.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

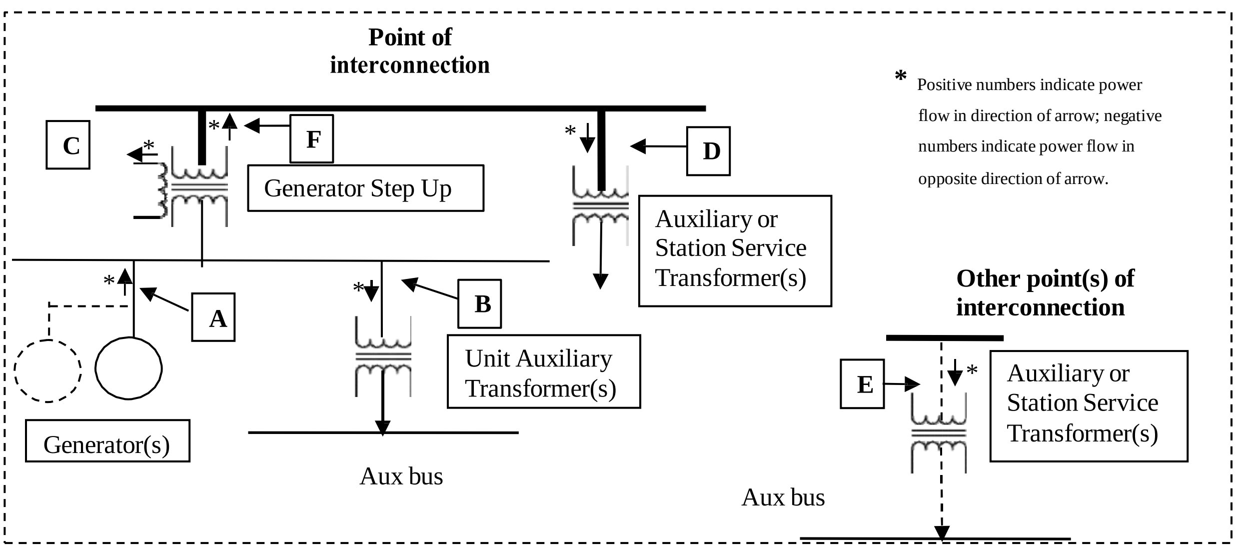
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: JM Shafer Generating Station **Unit: GTE** **Date of Report: 03/14/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**13.01 kV**	**14.10 MW**	**-19.00 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**233.80 kV**	**1.78 MW**	**0.89 Mvar**	Station Service Transformer #1
D2	**233.80 kV**	**1.46 MW**	**0.72 Mvar**	Station Service Transformer #2
D	**233.80 kV**	**3.24 MW**	**1.61 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**233.80 kV**	**14.10 MW**	**-21.84 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for GTD that was on-line and connected to the same GSU.				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**14.46 kV**	**14.00 MW**	**41.40 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**1.75 MW**	**0.89 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.46 MW**	**1.63 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**3.21 MW**	**2.52 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**13.08 MW**	**33.87 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for GTD that was on-line and connected to the same GSU.				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**12.30 kV**	**34.90 MW**	**-15.90 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**1.80 MW**	**0.89 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.45 MW**	**0.71 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**3.25 MW**	**1.60 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**34.29 MW**	**-28.41 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for GTD that was on-line and connected to the same GSU.				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**14.44 kV**	**34.90 MW**	**41.60 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**1.76 MW**	**0.89 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.44 MW**	**0.73 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**3.20 MW**	**1.62 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**33.54 MW**	**27.70 Mvar**	Net unit capability
Identify calculated values, if any: MW and Mvars adjusted for GTD that was on-line and connected to the same GSU.				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-15.90	
GSU Reactive Power (Mvar)	-12.51	
Net Leading Reactive Power Capability (Mvar)	-28.41	
Gross Lagging Reactive Power Capability (Mvar)	41.60	
GSU Lagging Reactive Power (Mvar)	11.79	
Net Lagging Reactive Power Capability (Mvar)	29.81	
Gross Real Power Capability Minimum Stable Load (MW)	14.00	
Gross Real Power Capability Maximum output (MW)	35.00	
Station Service Reactive Load (Mvar)	1.62	
Station Service Real Load (MW)	3.22	
Net Unit Maximum Real Power Output (MW)	31.78	
GSU Real Power Losses (MW)	2.92	
GSU Reactive Losses (Mvar)	-8.67	

Summary of Verification

- Date of Verification: 12/15/2015
- Verification Start Time: 09:30
- Verification End Time: 10:10
- Scheduled Voltage: 235 kV
- Transformer Voltage Ratio:
    - GSU: 17.9
    - AMF #1: 55.288
    - AMF#2: 55.288
- Transformer Tap Setting:
    - GSU: 2
    - AMF #1: 3
    - AMF#2: 3

- Ambient conditions at the end of the verification:
  - Air temperature: __20.0 °F__
  - Humidity: __90 %__

Date that data shown in last verification column in table above was taken: __12/15/2015__

Remarks :

Each unit at JM Shafer was verified separately.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

MOD-025 Attachment 2

<u>One-line Diagram, Table, and Summary for Verification Information Reporting</u>

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: JM Shafer Generating Station **Unit: STA** **Date of Report: 03/14/2016**

<u>Check all that apply:</u>

■ Over-excited Full Load Reactive Power Verification

■ Under-excited Full Load Reactive Power Verification

■ Over-excited Minimum Load Reactive Power Verification

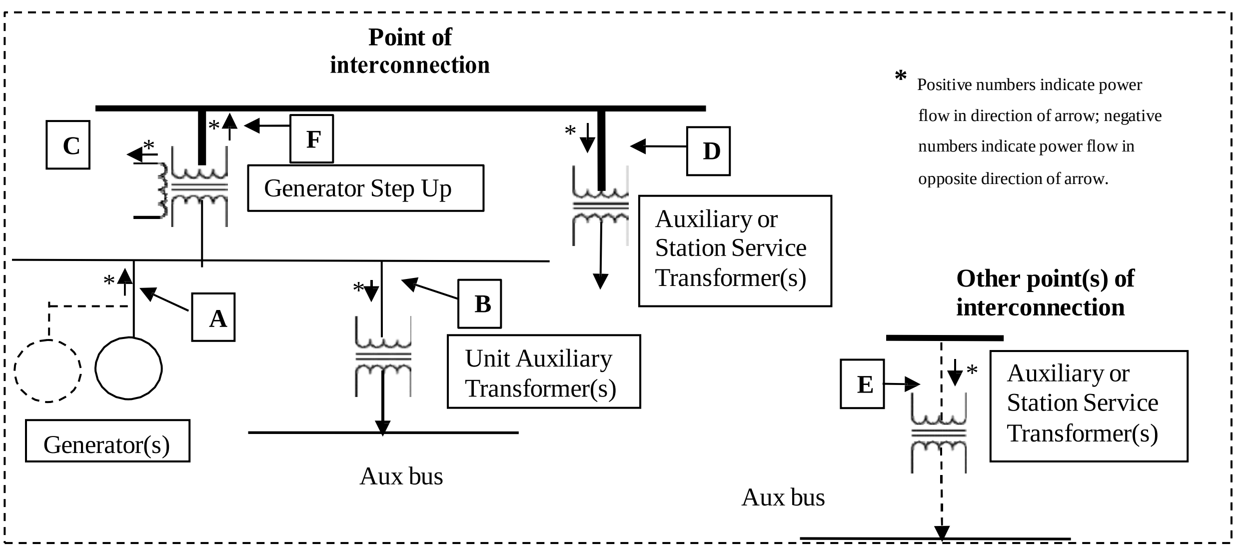
■ Under-excited Minimum Load Reactive Power Verification

■ Real Power Verification

■ Staged Test Data

☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**13.13 kV**	**6.80 MW**	**-18.60 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**234.0 kV**	**0.83 MW**	**0.31 Mvar**	Station Service Transformer #1
D2	**234.0 kV**	**1.25 MW**	**0.59 Mvar**	Station Service Transformer #2
D	**234.0 kV**	**2.08 MW**	**0.90 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**234.0 kV**	**6.18 MW**	**-19.54 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**14.63 kV**	**6.70 MW**	**25.50 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**0.84 MW**	**0.31 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.26 MW**	**0.6 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**2.10 MW**	**0.91 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**6.08 MW**	**23.66 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**13.40 kV**	**50.00 MW**	**-8.00 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**2.31 MW**	**1.13 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**2.94 MW**	**1.42 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**5.25 MW**	**2.55 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**235.0 kV**	**49.30 MW**	**-15.34 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**14.22 kV**	**50.00 MW**	**15.00 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**234.2 kV**	**2.32 MW**	**1.14 Mvar**	Station Service Transformer #1
D2	**234.2 kV**	**2.98 MW**	**1.44 Mvar**	Station Service Transformer #2
D	**234.2 kV**	**5.30 MW**	**2.58 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F	**234.2 kV**	**49.60 MW**	**7.60 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-8.00	
GSU Reactive Power (Mvar)	-7.34	
Net Leading Reactive Power Capability (Mvar)	-15.34	
Gross Lagging Reactive Power Capability (Mvar)	15.00	
GSU Lagging Reactive Power (Mvar)	7.40	
Net Lagging Reactive Power Capability (Mvar)	7.60	
Gross Real Power Capability Minimum Stable Load (MW)	6.75	
Gross Real Power Capability Maximum output (MW)	50.00	
Station Service Reactive Load (Mvar)	2.58	
Station Service Real Load (MW)	5.30	
Net Unit Maximum Real Power Output (MW)	44.70	
GSU Real Power Losses (MW)	0.58	
GSU Reactive Losses (Mvar)	-4.38	

Summary of Verification

- Date of Verification: 12/14/2015
- Verification Start Time: 11:50
- Verification End Time: 13:30
- Scheduled Voltage: 235 kV
- Transformer Voltage Ratio:
  - GSU: 17.9
  - AMF #1: 55.288
  - AMF#2: 55.288
- Transformer Tap Setting:
  - GSU: 2
  - AMF #1: 3
  - AMF#2: 3

- Ambient conditions at the end of the verification:
    - Air temperature: 34.3 °F
    - Humidity: 64 %

Date that data shown in last verification column in table above was taken: 12/14/2015

Remarks :

Each unit at JM Shafer was verified separately.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

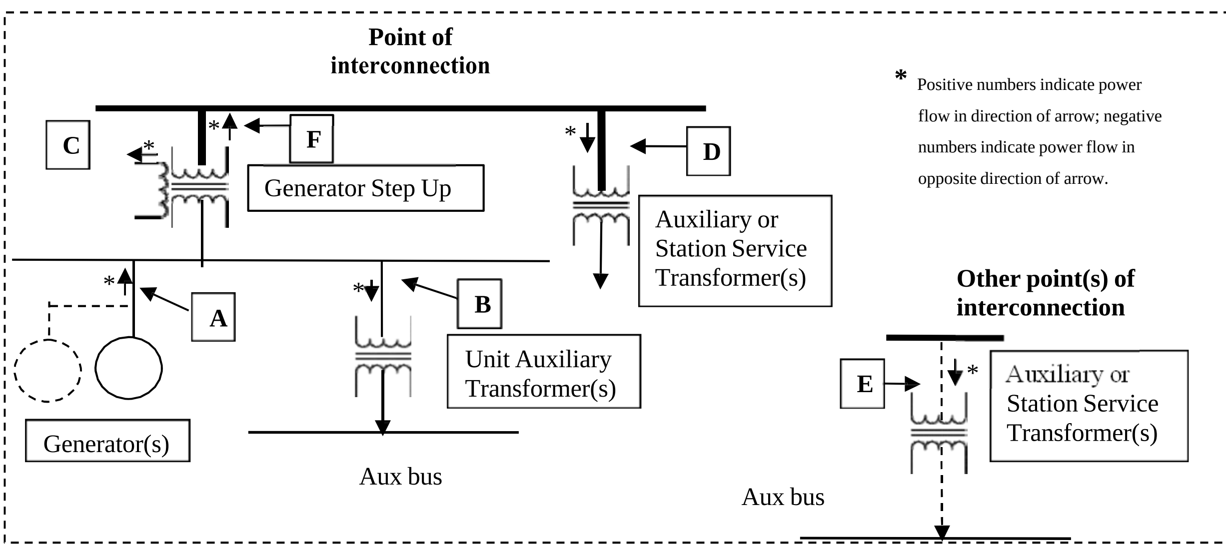
Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

Plant: JM Shafer Generating Station **Unit: STB** **Date of Report: 06/28/2016**

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A4	**13.13 kV**	**6.80 MW**	**-18.60 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**234.0 kV**	**0.83 MW**	**0.31 Mvar**	Station Service Transformer #1
D2	**234.0 kV**	**1.25 MW**	**0.59 Mvar**	Station Service Transformer #2
D	**234.0 kV**	**2.08 MW**	**0.90 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F3	**234.0 kV**	**6.18 MW**	**-19.54 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A4	**14.63 kV**	**6.70 MW**	**25.50 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**0.84 MW**	**0.31 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**1.26 MW**	**0.6 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**2.10 MW**	**0.91 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F3	**235.0 kV**	**6.08 MW**	**23.66 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A4	**13.40 kV**	**50.00 MW**	**-8.00 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**235.0 kV**	**2.31 MW**	**1.13 Mvar**	Station Service Transformer #1
D2	**235.0 kV**	**2.94 MW**	**1.42 Mvar**	Station Service Transformer #2
D	**235.0 kV**	**5.25 MW**	**2.55 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F3	**235.0 kV**	**49.30 MW**	**-15.34 Mvar**	Net unit capability
Identify calculated values, if any:				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A4	**14.22 kV**	**50.00 MW**	**15.00 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
D1	**234.2 kV**	**2.32 MW**	**1.14 Mvar**	Station Service Transformer #1
D2	**234.2 kV**	**2.98 MW**	**1.44 Mvar**	Station Service Transformer #2
D	**234.2 kV**	**5.30 MW**	**2.58 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: D=D1 + D2				
F3	**234.2 kV**	**49.60 MW**	**7.60 Mvar**	Net unit capability
Identify calculated values, if any:				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-8.00	
GSU Reactive Power (Mvar)	-7.34	
Net Leading Reactive Power Capability (Mvar)	-15.34	
Gross Lagging Reactive Power Capability (Mvar)	15.00	
GSU Lagging Reactive Power (Mvar)	7.40	
Net Lagging Reactive Power Capability (Mvar)	7.60	
Gross Real Power Capability Minimum Stable Load (MW)	6.75	
Gross Real Power Capability Maximum output (MW)	50.00	
Station Service Reactive Load (Mvar)	2.58	
Station Service Real Load (MW)	5.30	
Net Unit Maximum Real Power Output (MW)	44.70	
GSU Real Power Losses (MW)	0.58	
GSU Reactive Losses (Mvar)	-4.38	

Summary of Verification

- Date of Verification: 12/14/2015
- Verification Start Time: 11:50
- Verification End Time: 13:30
- Scheduled Voltage: 235 kV
- Transformer Voltage Ratio:
  - GSU: 17.9
  - AMF #1: 55.288
  - AMF#2: 55.288
- Transformer Tap Setting:
  - GSU: 2
  - AMF #1: 3
  - AMF#2: 3

- Ambient conditions at the end of the verification:
    - Air temperature: 34.3 °F
    - Humidity: 64 %

Date that data shown in last verification column in table above was taken: 12/14/2015

Remarks :

Each unit at JM Shafer was verified separately. The maximum load testing was conducted on 06//28/2016.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

Company: Tri-State Generation and Transmission Association Inc. **Reported By (name): David Readio**

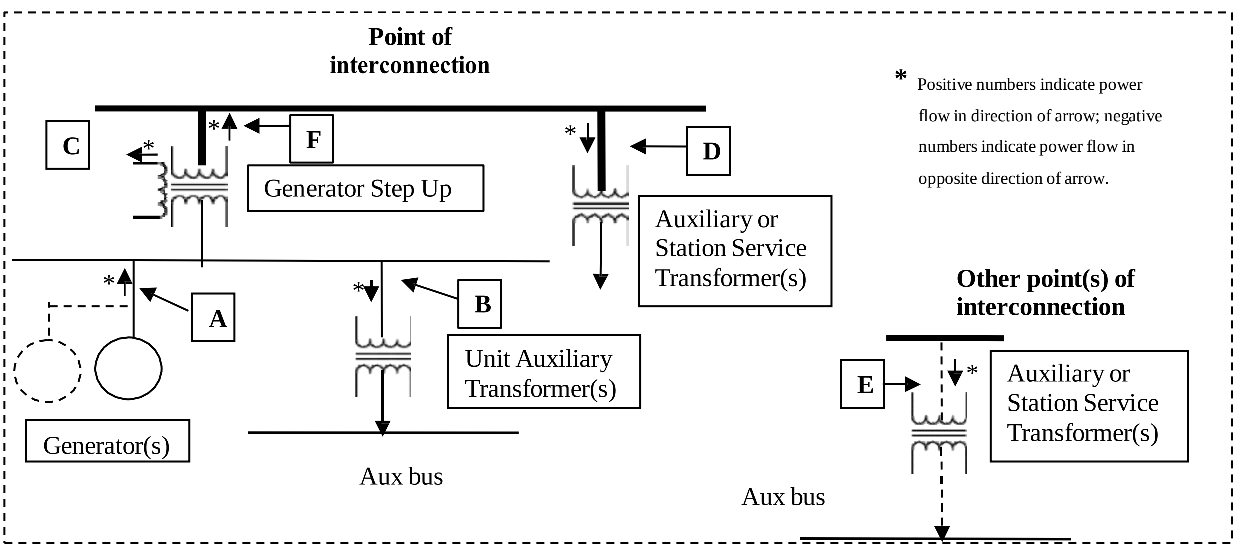
Plant: JM Shafer Generating Station **Unit: JM Shafer Generating Station**

Date of Report: 03/14/2016

Check all that apply:

- ■ Over-excited Full Load Reactive Power Verification
- ■ Under-excited Full Load Reactive Power Verification
- ■ Over-excited Minimum Load Reactive Power Verification
- ■ Under-excited Minimum Load Reactive Power Verification
- ■ Real Power Verification
- ■ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data: **(See attached simplified one-line diagram)**



Test Conducted at Minimum Stable Load at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**234.89 kV**	**76.20 MW**	**-132.0 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any: Average of all unit's minimum output				
D	**234.89 kV**	**2.48 MW**	**1.26 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: Average of Station Service at minimum output level				
F	**234.89 kV**	**72.52 MW**	**-151.44 Mvar**	Net unit capability
Identify calculated values, if any: Average of high side values				

Test Conducted at Minimum Stable Load at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**240.52 kV**	**76.20 MW**	**191.03 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any: Average of all unit's minimum output				
D	**240.52 kV**	**2.48 MW**	**1.26 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: Average of Station Service at minimum output level				
F	**240.52 kV**	**72.52 MW**	**233.93 Mvar**	Net unit capability
Identify calculated values, if any: Average of high side values				

Test Conducted at Maximum MW output at Max leading Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**234.89 kV**	**275.23 MW**	**-95.40 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any: Average of all unit's minimum output				
D	**234.89 kV**	**3.74 MW**	**1.85 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: Average of Station Service at minimum output level				
F	**234.89 kV**	**265.24 MW**	**-165.79 Mvar**	Net unit capability
Identify calculated values, if any: Average of high side values				

Test Conducted at Maximum MW output at Max lagging Mvar output:

Point	Voltage	Real Power	Reactive Power	Comment
A	**240.52 kV**	**275.23 MW**	**240.52 Mvar**	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any: Average of all unit's minimum output				
D	**240.52 kV**	**3.74 MW**	**1.85 Mvar**	Sum multiple unit auxiliary transformers.
Identify calculated values, if any: Average of Station Service at minimum output level				
F	**240.52 kV**	**265.24 MW**	**168.43 Mvar**	Net unit capability
Identify calculated values, if any: Average of high side values				

MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification

		(Previous Data; will be blank for the initial verification)
Gross Leading Reactive Power Capability (Mvar)	-95.40	
GSU Reactive Power (Mvar)	-70.39	
Net Leading Reactive Power Capability (Mvar)	-165.79	
Gross Lagging Reactive Power Capability (Mvar)	240.52	
GSU Lagging Reactive Power (Mvar)	168.43	
Net Lagging Reactive Power Capability (Mvar)	72.09	
Gross Real Power Capability Minimum Stable Load (MW)	76.20	
Gross Real Power Capability Maximum output (MW)	275.23	
Station Service Reactive Load (Mvar)	1.85	
Station Service Real Load (MW)	3.74	
Net Unit Maximum Real Power Output (MW)	271.49	
GSU Real Power Losses (MW)	9.98	
GSU Reactive Losses (Mvar)	71.24	

Summary of Verification

- Date of Verification: 12/14/2015
- Verification Start Time: 09:30
- Verification End Time: 15:02
- Scheduled Voltage: 235 kV
- Transformer Voltage Ratio:
  - GSU: 17.9
  - AMF #1: 55.288
  - AMF#2: 55.288
- Transformer Tap Setting:
  - GSU: 2
  - AMF #1: 3
  - AMF#2: 3
- Ambient conditions at the end of the verification:
  - Air temperature: 36.1 ºF

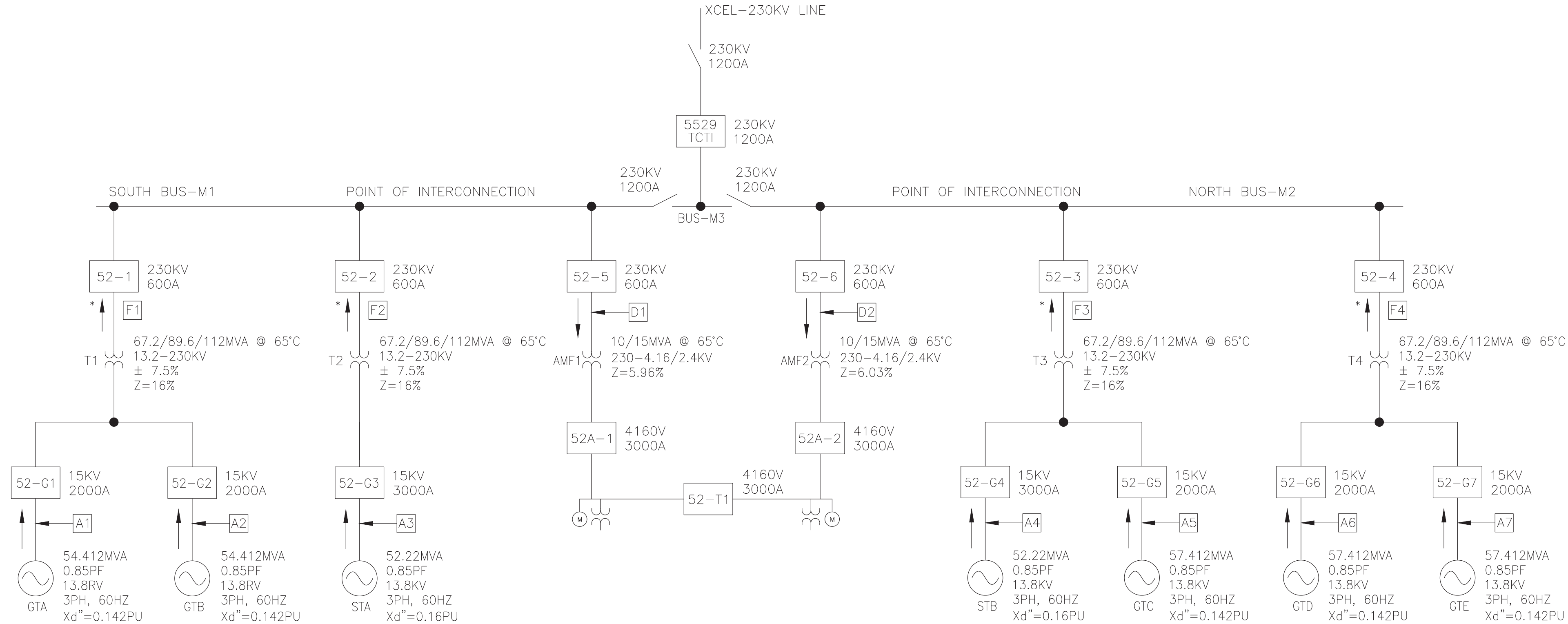
- Humidity: 61 %

Date that data shown in last verification column in table above was taken: 12/14/2015

Remarks :

Summary of all units taken together at either minimum stable load or at maximum real power output.

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.



JM SHAFER
NERC STANDARD MOD-025-2 ATTACHMENT 2 SIMPLIFIED ONE-LINE

NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	NO.	DATE	REVISION	DWN.	CHK'D	REFERENCE DWG'S

TRI-STATE
1100 W. 116th Ave.
P.O. Box 33695
Denver, Colorado 80233
303-452-6111

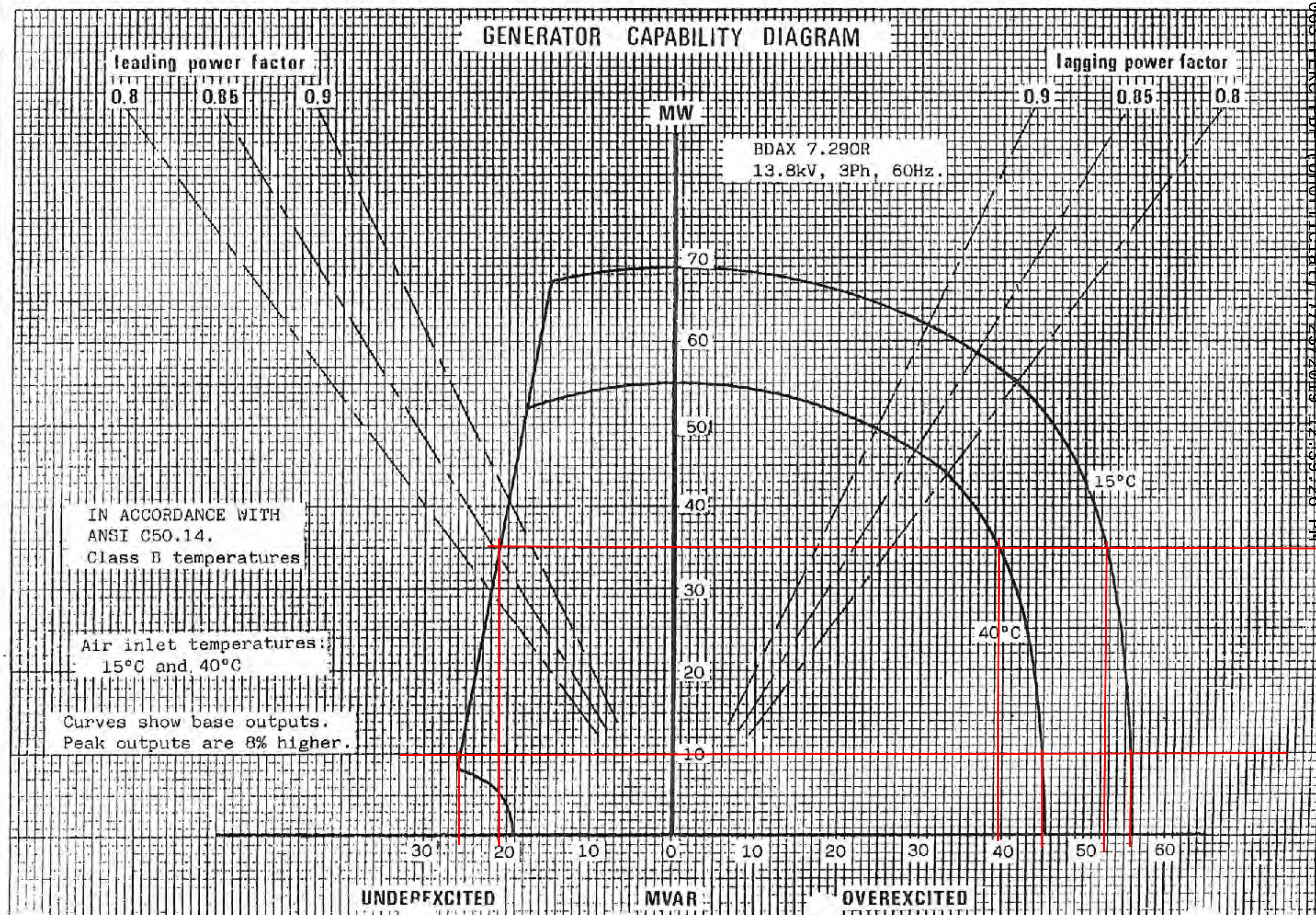
JM SHAFER STATION
SIMPLIFIED ONE-LINE DIAGRAM
FOR NERC STANDARD MOD-025-2

DWN. BARBARA HERRERA | SCALE NTS
CHK'D. DAVE READIO | DATE 04-17-15
APPR. DAVE READIO
DWG. NO. 0081-064-02-0031

E:\BC-WORKSPACE\EDMSVCP\M-EDMAPPP,D-TSGT-PROD\PROJECTS\CAPITAL\0081 - J.M. SHAFER - 0000 - DAVE READIO NERC AUDIT\0081-064-02-0031
EDM SERVICE ACCOUNT PROD
10/24/2012 9:49 AM

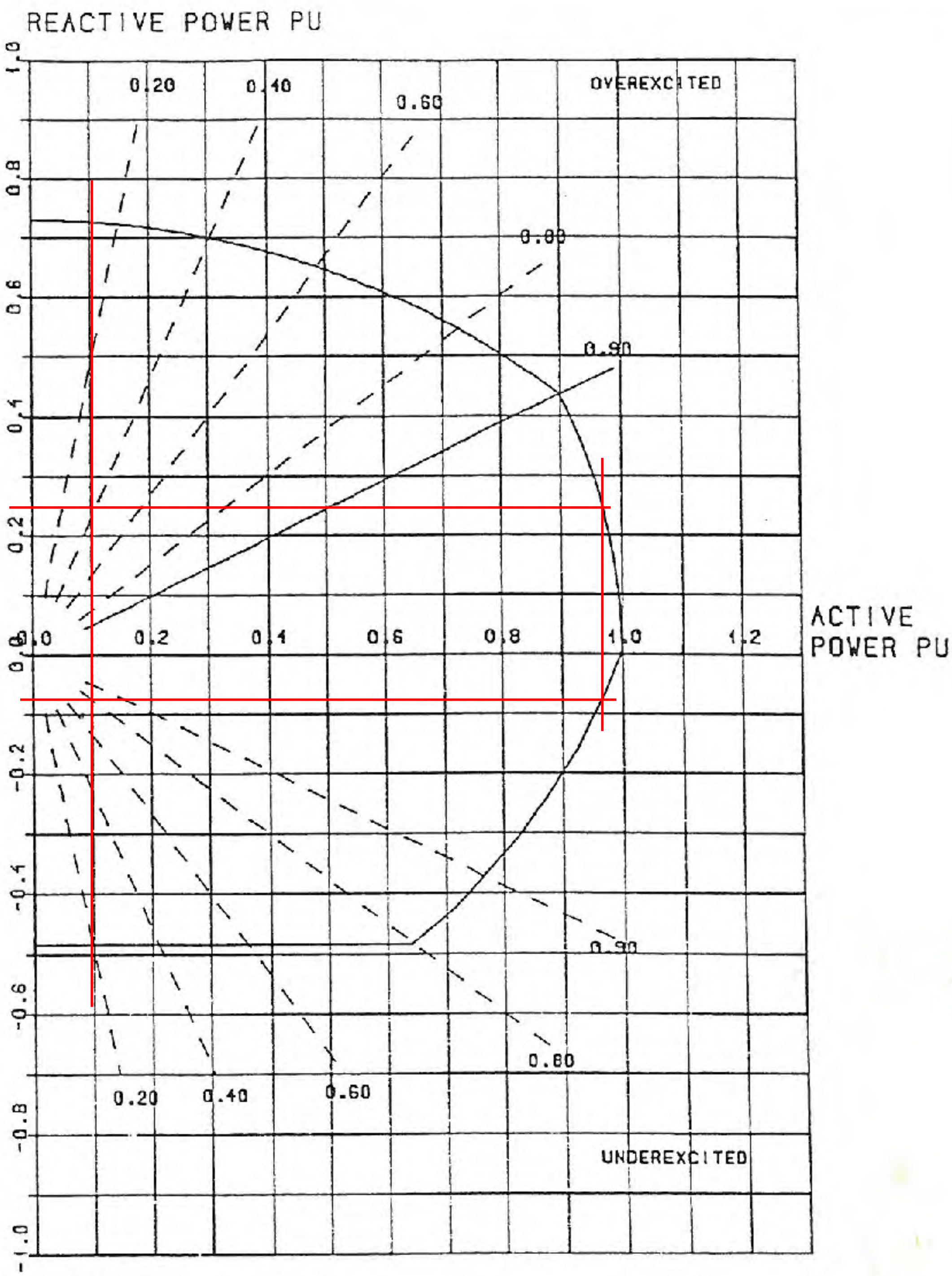
H.E.P. 5670.

Gas Turbines



ie No. 1: 30.4.86.

Steam Turbine



GEN/GKE 6P	CAPABILITY DIAGRAM	L 2861.0004
ABB GENERATION	GTL 1200EA 52220 KVA 0.90 PF 13800V 60 HZ 3600 RPM	92-10-28 GKE 56772

Testing Data
Tri-State Generation and Transmission Association
JM Shafer Generating Station

Date: (MM/DD/YY) 12/14/2015 **Unit:** GT-A

Time at start of Test (HH:MM): 10:14

Time at end of Test (HH:MM): 10:35

Air Temperature: 27.0 **(°F)** **Humidity:** 82.0 **%**

Cooling Water Temperature (if applicable): N/A **(°F)**

At minimum stable load:

Real Output of Generator: 12.0 **(MW)**

High Side (System) Voltage: 234.0 **(kV)**

Low Side (Generator) Voltage: 12.427 **(kV)**

Maximum lagging reactive power: -19.0 **(MVAr)**

Station Service real power load (AMF# 1): 0.84 **(MW)**

Station Service reactive power load (AMF# 1): 0.31 **(MVAr)**

Station Service real power load (AMF# 2): 1.11 **(MW)**

Station Service reactive power load (AMF# 2): 0.56 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 11.75 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): -20.58 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): N/A **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

N/A **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At minimum stable load:

Real Output of Generator: 12.20 **(MW)**

High Side (System) Voltage: 236.00 **(kV)**

Low Side (Generator) Voltage: 14.50 **(kV)**

Maximum leading reactive power: 39.60 **(MVAr)**

Station Service real power load (AMF# 1): 0.84 **(MW)**

Station Service reactive power load (AMF# 1): 0.33 **(MVAr)**

Station Service real power load (AMF# 2): 1.12 **(MW)**

Station Service reactive power load (AMF# 2): 0.58 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 12.19 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 35.70 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): N/A **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

N/A **(MVAr)** **Unit remained on-line?:** ☒ - **YES,** ☐ - **NO**

The remainder of this test was done on the following day, the conditions were recorded below.

Date of test: 12/15/2015 Time @ start of test: 11:25 Time @ end of test: 12:10

Temp: 20.3° F, Humidity: 90.0%

At maximum stable load:

Real Output of Generator: 35.4 **(MW)**

High Side (System) Voltage: 234.3 **(kV)**

Low Side (Generator) Voltage: 12.75 **(kV)**

Maximum lagging reactive power: -16.00 **(MVAr)**

Station Service real power load (AMF# 1): 1.76 **(MW)**

Station Service reactive power load (AMF# 1): 0.88 **(MVAr)**

Station Service real power load (AMF# 2): 1.45 **(MW)**

Station Service reactive power load (AMF# 2): 0.72 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 65.6 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): -13.9 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 30.49 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

14.37 **(MVAr)** **Unit remained on-line?:** ☒ **- YES,** ☐ **- NO**

For the second part of this test, once the system conditions below were met, the stator temperature was recorded, and after running under these conditions for an hour, the new temperature was again measured. The conditions and results are shown below:

At maximum stable load: Time @ start of test: 12:30 Starting Stator Temp: 118° F
Time @ end of test: 13:30 Ending Stator Temp: 175° F

Real Output of Generator: 35.3 **(MW)**

High Side (System) Voltage: 235.0 **(kV)**

Low Side (Generator) Voltage: 14.47 **(kV)**

Maximum leading reactive power: 41.40 **(MVAr)**

Station Service real power load (AMF# 1): 1.77 **(MW)**

Station Service reactive power load (AMF# 1): 0.89 **(MVAr)**

Station Service real power load (AMF# 2): 1.46 **(MW)**

Station Service reactive power load (AMF# 2): 0.73 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 65.00 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 30.00 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 29.75 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

3.21 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
JM Shafer Generating Station

Date: (MM/DD/YY) 12/15/2015 **Unit:** GT-B

Time at start of Test (HH:MM): 11:15

Time at end of Test (HH:MM): 12:02

Air Temperature: 20.3 **(°F)** **Humidity:** 90.0 **%**

Cooling Water Temperature (if applicable): N/A **(°F)**

At minimum stable load:

Real Output of Generator: 14.6 **(MW)**

High Side (System) Voltage: 235.0 **(kV)**

Low Side (Generator) Voltage: 12.43 **(kV)**

Maximum lagging reactive power: -19.0 **(MVAr)**

Station Service real power load (AMF# 1): 1.75 **(MW)**

Station Service reactive power load (AMF# 1): 0.88 **(MVAr)**

Station Service real power load (AMF# 2): 1.45 **(MW)**

Station Service reactive power load (AMF# 2): 0.71 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 38.16 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 44.10 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 24.2 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

2.4 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At minimum stable load:

Real Output of Generator: 14.0 **(MW)**

High Side (System) Voltage: 235.0 **(kV)**

Low Side (Generator) Voltage: 14.518 **(kV)**

Maximum leading reactive power: 42.21 **(MVAr)**

Station Service real power load (AMF# 1): 1.76 **(MW)**

Station Service reactive power load (AMF# 1): 0.88 **(MVAr)**

Station Service real power load (AMF# 2): 1.45 **(MW)**

Station Service reactive power load (AMF# 2): 0.73 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 38.15 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 35.50 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 24.15 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

1.06 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At maximum stable load:

Real Output of Generator: 34.8 **(MW)**

High Side (System) Voltage: 235 **(kV)**

Low Side (Generator) Voltage: 14.49 **(kV)**

Maximum leading reactive power: 43.11 **(MVAr)**

Station Service real power load (AMF# 1): 1.79 **(MW)**

Station Service reactive power load (AMF# 1): 0.90 **(MVAr)**

Station Service real power load (AMF# 2): 1.47 **(MW)**

Station Service reactive power load (AMF# 2): 0.73 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 51.8 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 32.8 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 17.01 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

0.48 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At maximum stable load:

Real Output of Generator: 35.0 **(MW)**

High Side (System) Voltage: 234.90 **(kV)**

Low Side (Generator) Voltage: 12.468 **(kV)**

Maximum lagging reactive power: -15.90 **(MVAr)**

Station Service real power load (AMF# 1): 1.77 **(MW)**

Station Service reactive power load (AMF# 1): 0.88 **(MVAr)**

Station Service real power load (AMF# 2): 1.45 **(MW)**

Station Service reactive power load (AMF# 2): 0.72 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 51.0 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): -23.5 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 15.6 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

0.90 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
JM Shafer Generating Station

Date: (MM/DD/YY) 12/14/2015 **Unit:** GT-C

Time at start of Test (HH:MM): 09:08

Time at end of Test (HH:MM): 10:02

Air Temperature: 22.6 **(^{o}F)** **Humidity:** 87 **%**

Cooling Water Temperature (if applicable): N/A **(^{o}F)**

At minimum stable load:

Real Output of Generator: 11.7 **(MW)**

High Side (System) Voltage: 235.0 **(kV)**

Low Side (Generator) Voltage: 12.43 **(kV)**

Maximum lagging reactive power: -19.10 **(MVAr)**

Station Service real power load (AMF# 1): 0.84 **(MW)**

Station Service reactive power load (AMF# 1): 0.31 **(MVAr)**

Station Service real power load (AMF# 2): 1.12 **(MW)**

Station Service reactive power load (AMF# 2): 0.56 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 11.44 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): -20.48 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): N/A **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

N/A **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At minimum stable load:

Real Output of Generator: 11.8 **(MW)**

High Side (System) Voltage: 235.0 **(kV)**

Low Side (Generator) Voltage: 14.483 **(kV)**

Maximum leading reactive power: 40.49 **(MVAr)**

Station Service real power load (AMF# 1): 0.84 **(MW)**

Station Service reactive power load (AMF# 1): 0.32 **(MVAr)**

Station Service real power load (AMF# 2): 1.18 **(MW)**

Station Service reactive power load (AMF# 2): 0.59 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 11.74 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 36.22 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): N/A **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

N/A **(MVAr)** **Unit remained on-line?:** ☒ - **YES,** ☐ - **NO**

The remainder of this test was accomplished on the following day due to favoring load status of the plant, the new conditions were recorded below.

Date of test: 12/15/2015, Start time: 10:50 End of Test: 11:13, Temp: 20.1°F, Humidity: 90%

At maximum stable load:

Real Output of Generator: 35.0 **(MW)**

High Side (System) Voltage: 235.0 **(kV)**

Low Side (Generator) Voltage: 14.44 **(kV)**

Maximum leading reactive power: 41 **(MVAr)**

Station Service real power load (AMF# 1): 1.77 **(MW)**

Station Service reactive power load (AMF# 1): 0.90 **(MVAr)**

Station Service real power load (AMF# 2): 1.45 **(MW)**

Station Service reactive power load (AMF# 2): 0.73 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 46.62 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 32.50 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 12.00 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

0.46 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At maximum stable load:

Real Output of Generator: 34.9 **(MW)**

High Side (System) Voltage: 235.0 **(kV)**

Low Side (Generator) Voltage: 12.465 **(kV)**

Maximum lagging reactive power: -15.9 **(MVAr)**

Station Service real power load (AMF# 1): 1.77 **(MW)**

Station Service reactive power load (AMF# 1): 0.88 **(MVAr)**

Station Service real power load (AMF# 2): 1.45 **(MW)**

Station Service reactive power load (AMF# 2): 0.72 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 46.34 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): -22.35 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 12.00 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

0.90 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
JM Shafer Generating Station

Date: (MM/DD/YY) 12/14/2015 **Unit:** GT-D

Time at start of Test (HH:MM): 10:47

Time at end of Test (HH:MM): 11:10

Air Temperature: 29.7 **(°F)** **Humidity:** 74 **%**

Cooling Water Temperature (if applicable): N/A **(°F)**

At minimum stable load:

Real Output of Generator: 11.9 **(MW)**

High Side (System) Voltage: 234.2 **(kV)**

Low Side (Generator) Voltage: 12.39 **(kV)**

Maximum lagging reactive power: -19.00 **(MVAr)**

Station Service real power load (AMF# 1): 0.82 **(MW)**

Station Service reactive power load (AMF# 1): 0.31 **(MVAr)**

Station Service real power load (AMF# 2): 1.22 **(MW)**

Station Service reactive power load (AMF# 2): 0.56 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 11.56 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): -20.54 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): N/A **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

N/A **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At minimum stable load:

Real Output of Generator: 12.0 **(MW)**

High Side (System) Voltage: 235.0 **(kV)**

Low Side (Generator) Voltage: 14.48 **(kV)**

Maximum leading reactive power: 40.58 **(MVAr)**

Station Service real power load (AMF# 1): 0.85 **(MW)**

Station Service reactive power load (AMF# 1): 0.32 **(MVAr)**

Station Service real power load (AMF# 2): 1.29 **(MW)**

Station Service reactive power load (AMF# 2): 0.60 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 12.25 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 36.25 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): N/A **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

N/A **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

The remainder of this test was completed on the following day when the plant was running at a load more suitable for maximum stable load.

Date of test: 12/15/2015, Temp: 20.1 F
Time @ start of test: 10:21 Humidity: 90.0%
Time @ end of test: 10:45

At maximum stable load:

Real Output of Generator: 34.9 **(MW)**

High Side (System) Voltage: 235.0 **(kV)**

Low Side (Generator) Voltage: 14.42 **(kV)**

Maximum leading reactive power: 43.41 **(MVAr)**

Station Service real power load (AMF# 1): 1.81 **(MW)**

Station Service reactive power load (AMF# 1): 0.90 **(MVAr)**

Station Service real power load (AMF# 2): 1.44 **(MW)**

Station Service reactive power load (AMF# 2): 0.72 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 68.36 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 27.85 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 31.90 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

0.15 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At maximum stable load:

Real Output of Generator: 35.15 **(MW)**

High Side (System) Voltage: 235.00 **(kV)**

Low Side (Generator) Voltage: 12.74 **(kV)**

Maximum lagging reactive power: -15.70 **(MVAr)**

Station Service real power load (AMF# 1): 1.76 **(MW)**

Station Service reactive power load (AMF# 1): 0.88 **(MVAr)**

Station Service real power load (AMF# 2): 1.46 **(MW)**

Station Service reactive power load (AMF# 2): 0.71 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 65.30 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): -17.78 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 31.30 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

11.15 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
JM Shafer Generating Station

Date: (MM/DD/YY) 12/15/2015 **Unit:** GT-E

Time at start of Test (HH:MM): 9:30

Time at end of Test (HH:MM): 10:10

Air Temperature: 20.0 **(°F)** **Humidity:** 90.0 **%**

Cooling Water Temperature (if applicable): N/A **(°F)**

At minimum stable load:

Real Output of Generator: 14.1 **(MW)**

High Side (System) Voltage: 233.8 **(kV)**

Low Side (Generator) Voltage: 13.01 **(kV)**

Maximum lagging reactive power: -19.10 **(MVAr)**

Station Service real power load (AMF# 1): 1.78 **(MW)**

Station Service reactive power load (AMF# 1): 0.89 **(MVAr)**

Station Service real power load (AMF# 2): 1.46 **(MW)**

Station Service reactive power load (AMF# 2): 0.72 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 30.68 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): -4.60 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 17.70 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

17.24 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At minimum stable load:

Real Output of Generator: 14.00 **(MW)**

High Side (System) Voltage: 235.00 **(kV)**

Low Side (Generator) Voltage: 14.46 **(kV)**

Maximum leading reactive power: 41.40 **(MVAr)**

Station Service real power load (AMF# 1): 1.75 **(MW)**

Station Service reactive power load (AMF# 1): 0.89 **(MVAr)**

Station Service real power load (AMF# 2): 1.46 **(MW)**

Station Service reactive power load (AMF# 2): 1.63 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 37.83 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 34.37 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 23.11 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

0.50 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At maximum stable load:

Real Output of Generator: 35.10 **(MW)**

High Side (System) Voltage: 235.05 **(kV)**

Low Side (Generator) Voltage: 12.30 **(kV)**

Maximum lagging reactive power: -15.90 **(MVAr)**

Station Service real power load (AMF# 1): 1.80 **(MW)**

Station Service reactive power load (AMF# 1): 0.89 **(MVAr)**

Station Service real power load (AMF# 2): 1.45 **(MW)**

Station Service reactive power load (AMF# 2): 0.71 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 64.93 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): -30.78 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 30.65 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

-2.37 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At maximum stable load:

Real Output of Generator: 34.9 **(MW)**

High Side (System) Voltage: 235.00 **(kV)**

Low Side (Generator) Voltage: 14.44 **(kV)**

Maximum leading reactive power: 41.60 **(MVAr)**

Station Service real power load (AMF# 1): 1.76 **(MW)**

Station Service reactive power load (AMF# 1): 0.89 **(MVAr)**

Station Service real power load (AMF# 2): 1.44 **(MW)**

Station Service reactive power load (AMF# 2): 0.73 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 54.5 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 31.0 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): 28.6 **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

1.19 **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

Testing Data
Tri-State Generation and Transmission Association
JM Shafer Generating Station

Date: (MM/DD/YY) 12/14/2015 **Unit:** STG-A

Time at start of Test (HH:MM): 11:50

Time at end of Test (HH:MM): 12:30

Air Temperature: 34.3 **(°F)** **Humidity:** 64.0 **%**

Cooling Water Temperature (if applicable): N/A **(°F)**

At minimum stable load:

Real Output of Generator: 6.8 **(MW)**

High Side (System) Voltage: 234.0 **(kV)**

Low Side (Generator) Voltage: 13.13 **(kV)**

Maximum lagging reactive power: -18.6 **(MVAr)**

Station Service real power load (AMF# 1): 0.83 **(MW)**

Station Service reactive power load (AMF# 1): 0.31 **(MVAr)**

Station Service real power load (AMF# 2): 1.25 **(MW)**

Station Service reactive power load (AMF# 2): 0.59 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 6.18 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): -19.54 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): N/A **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

N/A **(MVAr)**

Unit remained on-line?: ☒ **– YES,** ☐ **– NO**

At minimum stable load:

Real Output of Generator: 6.7 **(MW)**

High Side (System) Voltage: 235.0 **(kV)**

Low Side (Generator) Voltage: 14.63 **(kV)**

Maximum leading reactive power: 25.50 **(MVAr)**

Station Service real power load (AMF# 1): 0.84 **(MW)**

Station Service reactive power load (AMF# 1): 0.31 **(MVAr)**

Station Service real power load (AMF# 2): 1.26 **(MW)**

Station Service reactive power load (AMF# 2): 0.60 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 7.06 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 23.66 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): N/A **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

N/A **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At maximum stable load:

Real Output of Generator: 50.0 **(MW)**

High Side (System) Voltage: 234.10 **(kV)**

Low Side (Generator) Voltage: 13.40 **(kV)**

Maximum lagging reactive power: -8.00 **(MVAr)**

Station Service real power load (AMF# 1): 2.31 **(MW)**

Station Service reactive power load (AMF# 1): 1.13 **(MVAr)**

Station Service real power load (AMF# 2): 2.94 **(MW)**

Station Service reactive power load (AMF# 2): 1.42 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 49.3 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): -15.34 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): N/A **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

N/A **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

At maximum stable load:

Real Output of Generator: 50.00 **(MW)**

High Side (System) Voltage: 234.17 **(kV)**

Low Side (Generator) Voltage: 14.22 **(kV)**

Maximum leading reactive power: 15.00 **(MVAr)**

Station Service real power load (AMF# 1): 2.32 **(MW)**

Station Service reactive power load (AMF# 1): 1.14 **(MVAr)**

Station Service real power load (AMF# 2): 2.98 **(MW)**

Station Service reactive power load (AMF# 2): 1.44 **(MVAr)**

Real Power output of GSU transformer (T1, T2, T3 or T4): 49.6 **(MW)**

Reactive Power output of GSU Transformer (T1, T2, T3 or T4): 7.6 **(MVAr)**

Real Power of other generator connected to same GSU (if applicable): N/A **(MW)**

Reactive Power of other generator connected to same GSU (if applicable):

N/A **(MVAr)**

Unit remained on-line?: ☒ **- YES,** ☐ **- NO**

GTA

	Minimum Stable Load			Maximum Output		
	MW	MVAR	Voltage (kV)	MW	MVAR	Voltage (kV)
	--------------------	--------------------	--------------------	--------------------	--------------------	--------------------
Generator	12.00	-19.00	12.43	35.40	-16.00	12.75
GSU	11.75	-20.58	234.00	35.11	-28.27	234.30
Station Service	1.95	0.87	234.00	3.21	1.60	234.30
Generator	12.20	39.60	14.50	35.30	41.40	14.47
GSU	12.19	35.70	234.00	35.25	33.21	235.00
Station Service	1.96	0.91	234.00	3.23	1.62	235.00
GSU Losses	0.25	2.74		0.17	10.23	

GTB

	Minimum Stable Load			Maximum Output		
	MW	MVAR	Voltage (kV)	MW	MVAR	Voltage (kV)
	--------------------	--------------------	--------------------	--------------------	--------------------	--------------------
Generator	14.60	-19.00	12.43	34.80	43.11	14.49
GSU	13.96	-26.50	235.00	34.79	32.32	235.00
Station Service	3.20	1.59	235.00	3.26	1.63	235.00
Generator	14.00	42.21	14.52	35.00	-15.90	12.47
GSU	14.00	34.44	235.00	35.40	-24.40	234.90
Station Service	3.21	1.61	235.00	3.22	1.60	234.90
GSU Losses	0.32	7.64		0.21	9.65	

GTC

	Minimum Stable Load			Maximum Output		
	MW	MVAR	Voltage (kV)	MW	MVAR	Voltage (kV)
	--------------------	--------------------	--------------------	--------------------	--------------------	--------------------
Generator	11.70	-19.10	12.43	35.00	41.00	14.44
GSU	11.44	-20.48	235.00	34.62	32.04	235.00
Station Service	1.96	0.87	235.00	3.22	1.63	235.00
Generator	11.80	40.49	14.48	34.90	-15.90	12.47
GSU	11.74	36.22	235.00	34.34	-23.25	235.00
Station Service	2.02	0.91	235.00	3.22	1.60	234.90
GSU Losses	0.26	2.83		0.47	8.16	

GTD

	Minimum Stable Load			Maximum Output		
	MW	MVAR	Voltage (kV)	MW	MVAR	Voltage (kV)
	--------------------	--------------------	--------------------	--------------------	--------------------	--------------------
Generator	11.90	-19.00	12.39	34.90	43.41	14.42
GSU	11.56	-20.54	234.20	36.46	27.70	235.00
Station Service	2.04	0.87	234.20	3.25	1.62	235.00
Generator	12.00	40.58	14.48	35.15	-15.70	12.74
GSU	12.25	36.25	235.00	34.00	-28.93	235.00
Station Service	2.14	0.92	235.00	3.22	1.59	235.00
GSU Losses	0.30	2.94		1.36	14.47	

GTE

	Minimum Stable Load MW	Minimum Stable Load MVAR	Minimum Stable Load Voltage (kV)	Maximum Output MW	Maximum Output MVAR	Maximum Output Voltage (kV)
Generator	14.10	-19.00	13.01	34.90	41.60	14.44
GSU	12.98	-21.84	233.80	25.90	29.81	235.00
Station Service	3.24	1.61	233.80	3.20	1.62	235.00
Generator	14.00	41.40	14.46	35.10	-15.90	12.30
GSU	14.72	33.87	235.00	34.29	-28.41	235.05
Station Service	3.21	2.52	235.00	3.25	1.60	235.05
GSU Losses	0.92	5.19		4.91	12.15	

STA

	Minimum Stable Load MW	Minimum Stable Load MVAR	Minimum Stable Load Voltage (kV)	Maximum Output MW	Maximum Output MVAR	Maximum Output Voltage (kV)
Generator	6.80	-18.60	13.13	50.00	15.00	14.22
GSU	6.18	-19.54	234.00	49.60	7.60	234.17
Station Service	2.08	0.90	234.00	5.30	2.58	235.00
Generator	6.70	25.50	14.63	50.00	-8.00	13.40
GSU	7.06	23.66	235.00	49.30	-15.34	235.05
Station Service	2.10	0.91	235.00	5.25	2.55	235.05
GSU Losses	0.62	1.39		0.55	7.37	

STB

	Minimum Stable Load			Maximum Output		
	MW	MVAR	Voltage (kV)	MW	MVAR	Voltage (kV)
Generator	6.60	-18.30	12.62	50.00	15.00	14.22
GSU	5.52	-20.70	234.00	49.60	7.60	234.17
Station Service	2.69	1.38	234.00	5.30	2.58	235.00
Generator	4.00	38.00	14.42	50.00	-8.00	13.40
GSU	4.66	35.05	235.00	49.30	-15.34	235.05
Station Service	2.78	1.46	235.00	5.25	2.55	235.05
GSU Losses	0.87	2.68		0.55	7.37	

TRANSFORMER T1

	Minimum Stable Load MW	MVAR	Voltage (kV)	Maximum Output MW	MVAR	Voltage (kV)
GTA & GTB (Leading)	26.40	-38.00	12.43	70.25	-31.90	12.61
GTA & GTB (Lagging)	26.40	81.81	14.51	70.25	84.51	14.48
T1 (Leading)	25.95	-47.08	235.50	70.28	-52.67	234.95
T1 (Lagging)	25.95	70.14	235.50	70.28	65.53	234.95
GSU Losses	0.45	10.38		-0.03	19.88	

TRANSFORMER T2

	Minimum Stable Load MW	MVAR	Voltage (kV)	Maximum Output MW	MVAR	Voltage (kV)
STA (Leading)	6.75	-18.60	13.13	50.00	-8.00	13.40
STA (Lagging)	6.75	25.50	14.63	50.00	15.00	14.22
T2 (Leading)	6.62	-19.54	234.00	49.45	-15.34	235.05
T2 (Lagging)	6.62	23.66	235.00	49.45	7.60	234.17
GSU Losses	0.13	1.39		0.55	7.37	

TRANSFORMER T3

	Minimum Stable Load MW	MVAR	Voltage (kV)	Maximum Output MW	MVAR	Voltage (kV)
STB & GTC (Leading)	17.05	-37.40	12.53	84.95	-23.90	235.03
STB & GTC (Lagging)	17.05	1.74	14.45	84.95	56.00	235.00
T3 (Leading)	16.68	-41.18	234.50	83.93	-38.59	235.03
T3 (Lagging)	16.68	71.27	235.00	83.93	39.64	235.03
GSU Losses	0.37	32.88		1.02	15.53	

TRANSFORMER T4

	Minimum Stable Load MW	MVAR	Voltage (kV)	Maximum Output MW	MVAR	Voltage (kV)
GTD & GTE (Leading)	26.00	-38.00	12.70	70.03	-31.60	12.52
GTD & GTE (Lagging)	26.00	81.98	14.47	70.03	85.01	14.43
T4 (Leading)	25.76	-42.38	234.60	65.33	-57.34	235.00
T4 (Lagging)	25.76	70.12	235.00	65.33	57.51	235.00
GSU Losses	0.24	8.12		4.70	26.62	

Total For JM Shafer

	Minimum Stable Load				Maximum Output			
	MW	MVAR (Leading)	MVAR (Lagging)	Voltage (kV)	MW	MVAR (Leading)	MVAR (Lagging)	Voltage (kV)
Gross Output	76.20	-132.00	191.03	234.89	275.23	-95.40	240.52	
Station Service	2.48		1.26		3.74		1.85	
Net Output	72.52	-151.44	233.93		265.24	-165.79	168.43	
Total GSU Losses	3.68	19.44	42.90		9.98	70.39	72.09	

FERC rendition of the electronically filed tariff records in Docket No. ER19-02441-000
Filing Data:
CID: C003836
Filing Title: Baseline Open Access Transmission Tariff
Company Filing Identifier: 24
Type of Filing Code: 390
Associated Filing Identifier:
Tariff Title: Tri-State Open Access Transmission Tariff
Tariff ID: 18
Payment Confirmation:
Suspension Motion: N

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

OPEN ACCESS TRANSMISSION TARIFF

FERC ELECTRIC TARIFF

VOLUME NO. 2

TABLE OF CONTENTS

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 510
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

I. COMMON SERVICE PROVISIONS

1 Definitions

1.1 Affiliate:

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Ancillary Services:

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Transmission Costs:

The total annual cost of the Transmission System for purposes of

Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.4 Application:

A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.5 Commission:

The Federal Energy Regulatory Commission.

1.6 Completed Application:

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.7 Control Area:

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
2. maintain scheduled interchange with other Control Areas,

within the limits of Good Utility Practice;

3. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

4. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.8 Curtailment:

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.9 Delivering Party:

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.10 Designated Agent:

Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.11 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.12 Effective Date:

The Effective Date of this Tariff is the date specified in the Commission order approving the Tariff.

1.13 Eligible Customer:

i. Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider.

ii. Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.14 Facilities Study:

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.15 Firm Point-To-Point Transmission Service:

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.16 Good Utility Practice:

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a

reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.17 Interruption:

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.18 Load Ratio Share:

Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff and calculated on a rolling twelve month basis.

1.19 Load Shedding:

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.20 Long-Term Firm Point-To-Point Transmission Service:

Firm Point-To-Point Transmission Service under Part II of the Tariff with

a term of one year or more.

1.21 Native Load Customers:

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.22 Network Customer:

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.23 Network Integration Transmission Service:

The transmission service provided under Part III of the Tariff.

1.24 Network Load:

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A

Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.25 Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.26 Network Operating Committee:

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.27 Network Resource:

Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service

Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

1.28 Network Upgrades:

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.29 Non-Firm Point-To-Point Transmission Service:

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.30 Non-Firm Sale:

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the

buyer or seller.

1.31 Open Access Same-Time Information System (OASIS):

The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.32 Part I:

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.33 Part II:

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.34 Part III:

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.35 Parties:

The Transmission Provider and the Transmission Customer

receiving service under the Tariff.

1.36 Point(s) of Delivery:

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.37 Point(s) of Receipt:

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.38 Point-To-Point Transmission Service:

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.39 Power Purchaser:

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.40 Pre-Confirmed Application:

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.41 Receiving Party:

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.42 Regional Transmission Group (RTG):

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.43 Reserved Capacity:

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.44 Service Agreement:

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission

Provider for service under the Tariff.

1.45 Service Commencement Date:

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.46 Short-Term Firm Point-To-Point Transmission Service:

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.47 System Condition:

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.48 System Impact Study:

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be

incurred in order to provide transmission service.

1.49 Tariff: This Open Access Transmission Tariff, as on file with the Commission and in effect from time to time.

1.50 Third-Party Sale:

Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.51 Transmission Customer:

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.52 Transmission Provider:

Tri-State Generation and Transmission Association, Inc. is the public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.53 Transmission Provider's Monthly Transmission System

Peak: The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.54 Transmission Service:

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.55 Transmission System:

The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 520
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability:

For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the Effective Date will be

deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of five years or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service, the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service; provided that, the firm service customer shall have a right of first refusal at the end of such service only if the new contract is for five years or more. The existing

firm service customer must provide notice to the Transmission Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its transmission service agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. Service agreements subject to a right of first refusal entered into prior to the Effective Date or associated with a transmission service request received prior to July 13, 2007, unless terminated, will become subject to the five year/one year requirement on the first rollover date after the Effective Date; provided that, the one-year notice requirement shall apply to such service agreements with five years or more left in their terms as of the Effective Date.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 530
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the

Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Spinning, and (iv) Operating Reserve - Supplemental. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Provider is required to provide (or offer to arrange with the local Control Area Operator as discussed below), to the extent it is physically feasible to do so from its resources or from resources available to it, Generator Imbalance Service when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer using Transmission Service to deliver energy from a generator located within the Transmission Provider's Control Area is required to acquire Generator Imbalance Service, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in

Schedules 3, 4, 5, 6 and 9) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.7 below list the seven Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service:

The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation or Other Sources Service:

The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service:

Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service:

Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve - Spinning Reserve Service:

Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve - Supplemental Reserve Service:

Where applicable the rates and/or methodology are described in Schedule 6.

3.7 Generator Imbalance Service:

Where applicable the rates and/or methodology are described in Schedule 9.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 540
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR § 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities) and 18 CFR 38 of the Commission's regulations (Business Practice Standards and Communication

Protocols for Public Utilities). In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

The Transmission Provider shall post on OASIS and its public website an electronic link to all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff. The Transmission Provider shall post on OASIS and on its public website an electronic link to the NAESB website where any rules, standards and practices that are protected by copyright may be obtained. The Transmission Provider shall also post on OASIS and its public website an electronic link to a statement of the process by which the Transmission Provider shall add, delete or otherwise modify the rules, standards and practices that are not included in this Tariff. Such process shall set forth the means by which the Transmission Provider shall provide reasonable advance notice to Transmission Customers and Eligible Customers of any such additions, deletions or modifications, the associated effective date, and any additional implementation procedures that the Transmission Provider deems appropriate.

Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 550
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

5 Local Furnishing Bonds

5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds:

This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local furnishing bonds"). Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide transmission service to any Eligible Customer pursuant to this Tariff if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Provider's facilities that would be used in providing such transmission service.

5.2 Alternative Procedures for Requesting Transmission Service:

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such transmission service, it shall advise the Eligible Customer within thirty (30) days of

receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Transmission Provider's waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Transmission Provider shall be required to provide the requested transmission service in accordance with the terms and conditions of this Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 560
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates. A Transmission Customer that is a member of, or takes transmission service from, a power pool, Regional Transmission Group, Regional Transmission Organization (RTO), Independent System Operator (ISO) or other transmission organization approved by the Commission for the operation of transmission facilities also agrees to provide comparable transmission service to the transmission-owning members of such power pool and Regional Transmission Group, RTO, ISO or other transmission organization on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all

parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 570
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

7 Billing and Payment

7.1 Billing Procedure:

Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made

in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider.

7.2 Interest on Unpaid Balances:

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 CFR 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

7.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the

Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 580
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues:

Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues:

Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 590
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

9 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 600
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

10 Force Majeure and Indemnification

10.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing.

Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure.

However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 610
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

11 Creditworthiness

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures.

This review shall be made in accordance with standard commercial practices as described in Attachment L. In addition, the Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices that protects the Transmission Provider against the risk of non-payment.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 620
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures:

Any dispute between a Transmission Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a

senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days or such other period as the Parties may agree upon by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures:

Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration

Association and any applicable Commission regulations or Regional Transmission Group rules.

12.3 Arbitration Decisions:

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs:

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

1. the cost of the arbitrator chosen by the Party to sit on the three

member panel and one half of the cost of the third arbitrator chosen; or

2. one half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under The Federal Power Act:

Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 630
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

II. POINT-TO-POINT TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 640
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term:

The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority:

(i) Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis, i.e., in the chronological sequence in which each Transmission Customer has requested service.

(ii) Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction or reservation. However, Pre-Confirmed Applications for Short-Term Point-to-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed and that have equal or shorter duration. Among requests or reservations with the same duration and, as relevant, pre-confirmation status (pre-confirmed, confirmed, or not confirmed), priority will be given to an Eligible Customer's request or reservation that offers the highest price, followed by the date and time of the request or

reservation.

(iii) If the Transmission System becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, an Eligible Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. When a longer

duration request preempts multiple shorter duration reservations, the shorter duration reservations shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff.

(iv) Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after the Effective Date or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission

Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements:

The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and hat has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement. The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service

Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in Section 15.4, the Transmission Provider shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions.

Concurrent with such notice, the Transmission Provider shall provide the Transmission Customer with the reassessment study and a narrative description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs:

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider’s ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary

transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint by redispatching the Transmission Provider's resources, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 and agrees to either (i) compensate the Transmission Provider for any necessary transmission facility additions or (ii) accept the service subject to a biennial reassessment by the Transmission Provider of redispatch requirements as described in Section 15.4. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service:

In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system and the system directly and indirectly interconnected with Transmission Provider's Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. If

multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. Long-Term Firm Point-to-Point Service subject to conditions described in Section 15.4 shall be curtailed with secondary service in cases where the conditions apply, but otherwise will be curtailed on a pro rata basis with other Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected

Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service:

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the

Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed itsfirm capacity reserved at each Point of Receipt and each Point of

Delivery except as otherwise specified in Section 22. In the event that a Transmission Customer (including third party sales by the Transmission Provider) exceeds its firm Reserved Capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved, the Transmission Customer shall pay, in addition to the otherwise applicable charges, a penalty charge for the unauthorized use based upon the duration of the period when the unreserved service was actually used equal to twice the applicable rate for Firm Point-to-Point Transmission Service as follows: (1) For unauthorized use within a single day, the penalty charge shall be based on the daily rate. (2) For unauthorized use in two or more days in a calendar week, the penalty charge shall be based on the weekly rate. (3) For multiple instances of unauthorized use in more than one calendar week in a calendar month, the penalty charge shall be based on the monthly rate.

13.8 Scheduling of Firm Point-To-Point Transmission Service: Schedules for the Transmission Customer’s Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no

later than 10:00 a.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next scheduling interval provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any

schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 650
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term:

Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority:

Non-Firm Point-To-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers

taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned first to requests or reservations with a longer duration of service and second to Pre-Confirmed Applications. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term request before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusaldoes not agree to match the competing request: (a) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt

and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider:

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after the Effective Date or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements:

The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service:

Non-Firm Point-To-Point Transmission Service shall be offered under

terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff.. In the event that a Transmission Customer (including third party sales by the Transmission Provider) exceeds its non-firm Reserved Capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved, the Transmission Customer shall pay, in addition to the otherwise applicable charges, a penalty charge for the unauthorized use based upon the duration of the period when the unreserved service was actually used equal to twice the applicable rate for Firm Point-to-Point Transmission Service as follows: (1) For unauthorized use within a single day, the penalty charge shall be based on the daily rate. (2) For unauthorized use in two or more days in a calendar week, the penalty charge shall be based on the weekly rate. (3) For multiple instances of unauthorized use in more than one calendar week in a calendar month, the penalty charge shall be based on the monthly rate. Non-Firm Point-To-Point Transmission Service shall

include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2:00 p.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. will be accommodated, if practicable. Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider before the start of the next scheduling interval, provided that the Delivering Party and Receiving

Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service:

The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly and indirectly interconnected with Transmission Provider's Transmission System. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm

Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, (4) transmission service for Network Customers from non-designated resources, or (5) transmission service for Firm Point-to-Point Transmission Service during conditional curtailment periods as described in Section 15.4. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions).

Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any

Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 660
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

15 Service Availability

15.1 General Conditions:

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transfer Capability:

A description of the Transmission Provider's specific methodology for assessing available transfer capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff.

In the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement:

If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System,

Redispatch or Conditional Curtailment:

(a) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

(b) If the Transmission Provider determines that it cannot accommodate a Completed Application for Long-Term Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to provide redispatch from its

own resources until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide the redispatch, or (iii) the Transmission Customer terminates the service because of redispatch changes resulting from the reassessment. A Transmission Provider shall not unreasonably deny self-provided redispatch or redispatch arranged by the Transmission Customer from a third party resource.

(c) If the Transmission Provider determines that it cannot accommodate a Completed Application for Long-Term Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will offer the Firm Transmission Service with the condition that the Transmission Provider may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, the Transmission Provider will use due diligence to provide the service until (i) Network Upgrades are completed for the Transmission Customer,

(ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide such service, or

(iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

15.5 Deferral of Service:

The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules:

Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses:

Real Power Losses are associated with all transmission service. The

Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factor is 3.378%.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 670
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers:

Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

(a) The Transmission Customer has pending a Completed Application for service;

(b) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

(c) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission

Provider prior to the time service under Part II of the Tariff commences;

(d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation;

(e) The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment K; and

(f) The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements:

Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the

Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 680
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application:

A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written Application to:

OASIS/OATT Administrator

Tri-State Generation and Transmission Assoc., Inc.

P.O. Box 33695

Denver, CO 80233

at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited

procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS.

17.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or

judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service;

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A statement indicating that, if the Eligible Customer submits a Pre-Confirmed Application, the Eligible Customer will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service;

(x) North American Electric Reliability Corporation Identification; and

(xi) Any additional information required by the Transmission Provider's planning process established in Attachment K.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

17.3 Deposit:

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the

Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application:

If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application:

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transfer capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission Provider must be made as soon as

practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 Execution of Service Agreement:

Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service:

The Transmission Customer can obtain, subject to availability, up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a

non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof within 15 days of notifying the Transmission Provider it intends to extend the commencement of service. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 700
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application:

Eligible Customers seeking Non-Firm Point-To-Point Transmission

Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS.

18.2 Completed Application:

A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

(vi) North American Electric Reliability Corporation Identification.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vii) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(viii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

(ix) A statement indicating that, if the Eligible Customer submits a Pre-Confirmed Application, the Eligible Customer will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service:

Requests for monthly service shall be submitted <u>no earlier than sixty (60) days</u> before service is to commence; requests for weekly service shall be submitted <u>no earlier than fourteen (14) days</u> before service is to

commence, requests for daily service shall be submitted no earlier than two (2) days before service is

to commence, and requests for hourly service shall be submitted no earlier than noon the day before service is to commence. Requests for service received later than 2:00 p.m. prior to the day service is scheduled to commence will be accommodated if practicable [or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

18.4 Determination of Available Transfer Capability:

Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service. [Or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 710
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

19 Additional Study Procedures For Firm Point-To-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study:

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. Once informed, the Eligible Customer shall timely notify the Transmission Provider if it elects to have the Transmission Provider study redispatch or conditional curtailment as part of the System Impact Study. If notification is provided prior to tender of the System Impact Study Agreement, the Eligible Customer can avoid the costs associated with the study of these options. The Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission

Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for

service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures:

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify (1) any system constraints, identified with specificity by transmission element or flowgate, (2) redispatch options (when requested by an Eligible Customer) including an estimate of the cost of redispatch, (3) conditional curtailment options (when requested by an Eligible Customer) including the number of hours per year and the System Conditions during which conditional curtailment may occur, and (4) additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. For customers requesting the study of redispatch options, the System Impact Study shall (1) identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint and (2)

provide a measurement of each resource's impact on the system constraint. If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement

pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to

reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications:

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new

statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities:

The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service:

If the Transmission Provider determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission

Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities:

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service

Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

19.9 Penalties for Failure to Meet Study Deadlines:

Sections 19.3 and 19.4 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The Transmission Provider is required to file a notice with the Commission in the event that more than twenty (20) percent of non-Affiliates' System Impact Studies and Facilities Studies completed by the Transmission Provider in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of non-Affiliates' System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the Transmission Provider shall consider all System Impact Studies and Facilities Studies that it completes for non-Affiliates during the calendar quarter. The percentage

should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The Transmission Provider may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The Transmission Provider is subject to an operational penalty if it completes ten (10) percent or more of non-Affiliates' System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the Transmission Provider's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the Transmission Provider completes at least ninety (90) percent of all non-Affiliates' System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the Transmission Provider takes to complete that study beyond the 60-day deadline.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 720
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

20 Procedures if The Transmission Provider is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays in Construction of New Facilities:

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in

the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions:

When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

20.3 Refund Obligation for Unfinished Facility Additions:

If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000   Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 730
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions:

The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the

Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions:

In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the

Commission for resolution.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 740
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis:

The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification On a Firm Basis:

Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission

Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 750
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service:

(a) A Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

(b) The Assignee must execute a service agreement with the Transmission Provider governing reassignments of transmission service prior to the date on which the reassigned service commences. The Transmission Provider shall charge the Reseller, as appropriate, at the rate stated in the Reseller's

Service Agreement with the Transmission Provider or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the Transmission Provider or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service:

If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System

Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Transmission Provider and the Reseller through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service:

In accordance with Section 4, all sales or assignments of capacity must be conducted through or otherwise posted on the Transmission Provider's OASIS on or before the date the reassigned service commences and are subject to Section 23.1. Resellers may also use the Transmission Provider's OASIS to post transmission capacity available for resale.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 760
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being

transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data:

The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor:

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 770
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use

Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 780
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 790
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point

Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved by redispatching the Transmission Provider's resources to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 800
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

III. NETWORK INTEGRATION TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the

Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 810
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

28 Nature of Network Integration Transmission Service

28.1 Scope of Service:

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider’s Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities:

The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its

planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service:

The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native

Load Customers.

28.4 Secondary Service:

The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses:

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factor is 3.378%.

28.6 Restrictions on Use of Service:

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or

(ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. In the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve its Network Load, it shall pay the penalty set forth in Section 13.7 for the amount of service used to facilitate the wholesale sale.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 820
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

29 Initiating Service

29.1 Condition Precedent for Receiving Service:

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete

the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G, or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.

29.2 Application Procedures:

An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible

Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions

  -Any periods of restricted operations throughout the year

  - Maintenance schedules

  - Minimum loading level of unit

  -Normal operating level of unit

  -Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWH) for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a

portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource
- Amount of power to which the customer has rights
- Identification of the control area from which the power will originate
- Delivery point(s) to the Transmission Provider's Transmission System
- Transmission arrangements on the external transmission system(s)
- Operating restrictions, if any

  -Any periods of restricted operations throughout the year

  - Maintenance schedules

  - Minimum loading level of unit

  -Normal operating level of unit

  - Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWH) for redispatch computations;

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- 10 year projection of system expansions or upgrades
- Transmission System maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The

minimum term for Network Integration Transmission Service is one year;

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 29.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program; and

(ix) Any additional information required of the Transmission Customer as specified in the Transmission Provider's planning process established in Attachment K.

North American Electric Reliability Corporation Identification unless the Parties agree to a different time frame, the Transmission Provider must

acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service:

Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any

additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities:

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

‘ Filing of Service Agreement:

The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

Priority Order: 830
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

30 Network Resources

30.1 Designation of Network Resources:

Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources:

The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following

conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.3 Termination of Network Resources:

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource by providing notification to the Transmission Provider through OASIS as soon as reasonably practicable, but not later than the firm scheduling deadline for the period of termination. Any request for termination of Network Resource status must be submitted on OASIS, and should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time

that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

(i) Effective date and time of temporary termination;

(ii) Effective date and time of redesignation, following period of temporary termination;

(iii) Identification and capacity of resource(s) or portions thereof to be temporarily terminated;

(iv) Resource description and attestation for redesignating the network resource following the temporary termination, in accordance with Section 30.2; and

(v) Identification of any related transmission service requests to be evaluated concomitantly with the request for temporary termination, such that the requests for undesignation and the request for these related transmission service requests must be approved or denied as a single request. The evaluation of these related transmission service requests must take into account the termination of the network resources identified in (iii) above, as well as all competing transmission service

requests of higher priority.

As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.4 Operation of Network Resources:

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Areasuch that the output of those facilities exceeds its designated Network Load, plus Non-Firm Sales delivered pursuant to Part II of the Tariff, plus losses, plus power sales under a reserve sharing program, plus sales that permit curtailment without penalty to serve its designated Network Load. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the Transmission Provider's Transmission System, the Network Customer may not schedule

delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. In the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point to Point Transmission Service, it shall pay the penalty set forth in Section 13.7 for the amount of service exceeding the Network Resource's designated capacity.

30.5 Network Customer Redispatch Obligation:

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider:

The Network Customer shall be responsible for any arrangements

necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources:

The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer:

There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

30.9 Network Customer Owned Transmission Facilities:

The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider, to serve its power and transmission customers. For facilities added by the Network Customer subsequent to the May 14, 2007, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Provider's facilities; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's annual transmission revenue requirement as specified in Attachment H. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 840
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

31 Designation of Network Load

31.1 Network Load:

The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider:

The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with Commission policies.

31.3 Network Load Not Physically Interconnected with the

Transmission Provider:

This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points:

To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests:

Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner. **31.6 Annual Load and Resource Information Updates:**

The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff including, but not limited to, any information provided under section 29.2(ix) pursuant to the Transmission Provider's planning process in Attachment K. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to

provide reliable service.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 850
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

32 Additional Study Procedures For Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study:

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to

execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible

Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures:

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify (1) any system constraints, identified with specificity by transmission element or flowgate, (2) redispatch options (when requested by an Eligible Customer) including, to the extent possible, an estimate of the cost of redispatch, (3) available options for installation of automatic devices to curtail service (when requested by an Eligible Customer), and (4) additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. For customers requesting the study of redispatch options, the System Impact Study shall (1) identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint and (2) provide a measurement of each resource's impact on the

system constraint. If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be

charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

32.5 Penalties for Failure to Meet Study Deadlines:

Section 19.9 defines penalties that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Part II of the Tariff. These same requirements and penalties apply to service under Part III of the Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 860
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

33 Load Shedding and Curtailments

33.1 Procedures:

Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System and on systems directly and indirectly interconnected with Transmission Provider's Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints:

During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission

System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints:

Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries:

If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement or pursuant to the Transmission Loading Relief procedures specified in

Attachment J.

33.5 Allocation of Curtailments:

The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding:

To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability:

Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a

not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. In the event that a Network Customer fails to respond to established Load Shedding and Curtailment procedures or to cease or reduce service in response to a directive by the Transmission Provider, the Network

Customer shall pay the applicable charges and the following penalty (in addition to the charges for all of the service used) for the applicable month, 200% of the Network Integration Transmission Service charge. This penalty shall apply only to the portion of the service that the Transmission Customer fails to curtail in response to a Curtailment directive.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 870
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge:

The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Transmission Provider's Annual Transmission Revenue Requirement specified in Schedule H.

34.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly

load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load:

The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge:

The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery:

The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However,

the Transmission Provider must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 880
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

35 Operating Arrangements

35.1 Operation under The Network Operating Agreement:

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement:

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network

Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 CFR 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee:

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 890
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling,

System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

See annual Formula Rate Template (Attachment M) posted on the Transmission Provider's OASIS:

The charges shall be subject to change in accordance with the associated Implementation Protocols set forth in Attachment M of this Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 900
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's

transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

1) Yearly delivery: $1.09028 /kW-year

2) Monthly delivery: $0.09086 /kW-month

3) Weekly delivery: $0.02097 /kW-week

4) Daily delivery: $ 0.00299 /kW-day

5) mills per kWh: $ 0.12446/kW-hour

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 910
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The Transmission Provider will take into account the speed and accuracy of regulation resources in its

determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 920
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 4

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make

alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly energy imbalances under this Schedule or a penalty for hourly generator imbalances under Schedule 9 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of incremental or decremental cost; (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer’s scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that

occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of incremental cost or 75 percent of decremental cost.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched for any purpose, e.g., to supply the Transmission Provider's Native Load Customers, correct imbalances, or make off-system sales, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 930
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control

Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 940
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative

comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 950
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below.

See annual Formula Rate Template (Attachment M) posted on the Transmission Provider's OASIS:

The charges shall be subject to change in accordance with the associated Implementation Protocols set forth in Attachment M of this Tariff.

1) **Yearly delivery**: $___/KW of Reserved Capacity per year identified on

Page 1 (“Rates”) of the Transmission Provider’s Formula Rate Template.

2) **Monthly delivery**: $___/KW of Reserved Capacity per month identified on Page 1 (“Rates”) of the Transmission Provider’s Formula Rate Template.

3) **Weekly delivery**: $___/KW of Reserved Capacity per week identified on Page 1 (“Rates”) of the Transmission Provider’s Formula Rate Template.

4) **Daily delivery**: $___/KW of Reserved Capacity per day identified on Page 1 (“Rates”) of the Transmission Provider’s Formula Rate Template.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on

the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

7) **Gross Receipts Tax:** Where applicable, billings under this Schedule 7 shall be increased by an amount equal to the sum of taxes, fees and charges levied or assessed by any governmental or tribal authority specifically on the service rendered under this Schedule 7, or the right or privilege of rendering the service, or on any object or event incidental to the rendition of service. Nothing herein shall prevent the Transmission Customer from opposing any State or tribal taxing authority's determination that revenue-related taxes are applicable to service provided under this Schedule 7.

8) **FERC Annual Charge Fee:** An administrative charge shall be applied to all transmission services to recover the cost of the Commission annual charge (Annual Charge) under Part 382 of the Commission's regulations. The

Commission issues the invoice for the Annual Charge to Transmission Provider based on their megawatt-hours (MWH) of transmission of electric energy in interstate commerce as reported under the FERC Reporting Requirement 582. The charge factor or billing rate for Transmission Provider is calculated by the Commission on its Annual Charge invoice and is identified on the Rates tab of the Transmission Provider's Formula Rate template posted on the Transmission Provider's OASIS. Transmission Provider shall include the posted Annual Charge, as part of its annual informational filing. The posted Annual Charge billing rate shall then be billed for all MWH of transmission service to the individual Transmission Customer during the Formula Rate year. This will be a direct pass through of the FERC Annual Charge.

No Transmission Customer shall request that the FERC Annual Charge billing rate be placed into effect subject to suspension or refund or that the Commission otherwise condition recovery of such FERC Annual Charge. However, each such Transmission Customer reserves its rights, if any, to challenge, or seek refunds concerning any such FERC Annual Charge to the extent such FERC Annual Charge does not reflect a simple and accurate pass-through of the FERC Annual Charge.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 960
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-

Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

See annual Formula Rate Template (Attachment M) posted on the Transmission Provider's OASIS:

The charges shall be subject to change in accordance with the associated Implementation Protocols set forth in Attachment M of this tariff.

1) **Monthly delivery**: $___/KW of Reserved Capacity per month identified on Page 1 ("Rates") of the Transmission Provider's Formula Rate Template.

2) **Weekly delivery**: $___/KW of Reserved Capacity per week identified on Page 1 ("Rates") of the Transmission Provider's Formula Rate Template.

3) **Daily delivery**: $___/KW of Reserved Capacity per day identified on Page 1 ("Rates") of the Transmission Provider's Formula Rate template.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at thetime this service is reserved and in no event shall exceed $____/KWH on-peak or $_____/KWH off peak identified on Page 1 (“Rates”) of the Transmission Provider’s Formula Rate template.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must

occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

7) **Gross Receipt Tax:** Where applicable, billings under this Schedule 8 shall be increased by an amount equal to the sum of taxes, fees and charges levied or assessed by any governmental or tribal authority specifically on the service rendered under this Schedule 8, or the right or privilege of rendering the service, or on any object or event incidental to the rendition of service. Nothing herein shall prevent the Transmission Customer from opposing any State or tribal taxing authority's determination that revenue-related taxes are applicable to service provided under this Schedule 8.

8) **FERC Annual Charge Fee:** An administrative charge shall be applied to all transmission services to recover the cost of the Commission annual charge (Annual Charge) under Part 382 of the Commission's regulations. The

Commission issues the invoice for the Annual Charge to Transmission Provider based on their megawatt-hours (MWH) of transmission of electric energy in interstate commerce as reported under the FERC Reporting Requirement 582. The charge factor or billing rate for Transmission Provider is calculated by the Commission on its Annual Charge invoice and is identified on the on the Rates tab of the Transmission Provider's Formula Rate template posted on the Transmission Provider's OASIS. Transmission Provider shall include the posted Annual Charge, as part of its annual informational filing. The posted Annual Charge billing rate shall then be billed for all MWH of transmission service to the individual Transmission Customer during the Formula Rate year. This will be a direct pass through of the FERC Annual Charge.

No Transmission Customer shall request that the FERC Annual Charge billing rate be placed into effect subject to suspension or refund or that the Commission otherwise condition recovery of such FERC Annual Charge. However, each such Transmission Customer reserves its rights, if any, to challenge, or seek refunds concerning any such FERC Annual Charge to the extent such FERC Annual Charge does not reflect a simple and accurate pass-through of the FERC Annual Charge.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 970
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SCHEDULE 9

Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located in the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. The Transmission Provider must offer this service, to the extent it is physically feasible to do so from its resources or from resources available to it, when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule or a penalty for hourly energy imbalances under Schedule 4 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

The Transmission Provider shall establish charges for generator imbalance

based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of each month, at 100 percent of incremental or decremental cost, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of incremental cost or 75 percent of decremental cost, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

Notwithstanding the foregoing, deviations from scheduled transactions in order to respond to directives by the Transmission Provider, a balancing authority, or

a reliability coordinator shall not be subject to the deviation bands identified above and, instead, shall be settled financially, at the end of the month, at 100 percent of incremental and decremental cost. Such directives may include instructions to correct frequency decay, respond to a reserve sharing event, or change output to relieve congestion.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched for any purpose, e.g., to supply the Transmission Provider's Native Load Customers, correct imbalances, or make off-system sales, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 980
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT A

Form Of Service Agreement For Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and

between Tri-State Generation and Transmission Association, Inc.(the Transmission Provider), and ____________________________________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Tri-State Generation and Transmission Association, Inc.
Attn: OASIS/OATT Administrator

Direct Mail and Overnight Mail: 1100 W. 116th Ave., Westminster, CO 80234

or via OATTAdmin@tristategt.org

Transmission Customer:

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

Name	Title	Date

Transmission Customer:

By:

Name	Title	Date

Specifications For Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ____________________________________

Start Date:____

Termination Date: ______________________________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0Point(s) of Receipt: ___________________________________

Delivering Party: ___________________________________

4.0Point(s) of Delivery:___________________________________

Receiving Party:____________________________________

5.0Maximum amount of capacity and energy to be transmitted (Reserved Capacity): ________________________________

6.0Designation of party(ies) subject to reciprocal service obligation: ____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service:

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions

will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:

8.4

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 990
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT A-1

Form Of Service Agreement For The Resale, Reassignment Or Transfer Of Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between ____________ (the Transmission Provider), and ____________________ (the Assignee).

2.0 The Assignee has been determined by the Transmission Provider to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part II of the Transmission Provider's Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section 23.1 of this Tariff) and the Assignee, to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and
delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

4.0 The Transmission Provider shall credit the Reseller for the price reflected in the Assignee's Service Agreement or the associated OASIS schedule.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:
Tri-State Generation and Transmission Association, Inc.
Attn: OASIS/OATT Administrator

Direct Mail and Overnight Mail: 1100 W. 116th Ave., Westminster, CO 80234

or via OATTAdmin@tristategt.org

Assignee:

6.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:_

By:
Name Title Date

Assignee:

By:
Name Title Date

Specifications For The Resale, Reassignment Or Transfer of Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ____________________________________

Start Date: ____

Termination Date: ______________________________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0Point(s) of Receipt: ______________________________

Delivering Party: ______________________________

4.0Point(s) of Delivery:______________________________

Receiving Party:_______________________________

5.0Maximum amount of reassigned capacity: ___________

6.0Designation of party(ies) subject to reciprocal service obligation: ___________________________________

7.0 Name(s) of any Intervening Systems providing transmission service:

8.0 Service under this Agreement may be subject to some combination of the charges

detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:

8.2 System Impact and/or Facilities Study Charge(s):

8.3 Direct Assignment Facilities Charge:

____

____

8.4 Ancillary Services Charges:

9.0 Name of the Reseller of the reassigned transmission capacity:

____

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 1000
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT B

Form Of Service Agreement For Non-Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of ________________, is entered into, by and between Tri-State Generation and Transmission Association, Inc.(the Transmission Provider), and ____ (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Tri-State Generation and Transmission Association, Inc.
Attn: OASIS/OATT Administrator

Direct Mail and Overnight Mail: 1100 W. 116th Ave., Westminster, CO 80234
or via OATTAdmin@tristategt.org

Transmission Customer:

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

Name Title Date

Tra Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 1010
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT C

Methodology To Assess Available Transfer Capability

This Attachment C contains the Transmission Provider's methodology for determination of Available Transfer Capability (ATC).

1. Definitions

1.1 Total Transfer Capability (TTC) – The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.

1.2 Available Transfer Capability (ATC) – The measure of the transfer capability remaining in the physical transmission network for the further commercial activity over and above already committed uses. From a mathematical standpoint, ATC is defined as the Total Transfer Capability (TTC) less the Existing Transmission Commitments (ETC),

less a Capacity Benefit Margin (CBM), less any Transmission Reliability Margin (TRM), plus any Postbacks and Counterflows.

1.3 Existing Transmission Commitments (ETC) – A Transmission Provider's existing transmission capacity obligations which may include grandfathered transmission contracts, Tariff transmission reservations (including rollover rights for extensions) and other obligations that impact firm ATC.

1.4 Capacity Benefit Margin (CBM) – The amount of firm transmission transfer capability preserved by the Transmission Provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

1.5 Transmission Reliability Margin (TRM) – The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

1.6 Postbacks – A variable component of the Transmission Provider's selected ATC calculation methodology that positively impacts ATC based on a change in status of a

Transmission Service reservation or use of reserved capacity, or other conditions as specified by the Transmission Provider.

1.7 Counterflows – A variable component of the Transmission Provider's selected ATC calculation methodology that impacts ATC in a direction counter to prevailing TTC rating.

1.8 Scheduling Horizon – A specified number of hours extending past the current hour. For the Transmission Provider, the OASIS Scheduling Horizon is equal to the current hour plus eight (8) hours.

1.9 Operating Horizon – A specified number of hours extending past the end of the Scheduling Horizon. For the Transmission Provider, the OASIS Operating Horizon is equal to the end of the Scheduling Horizon plus 168 hours.

1.10 Planning Horizon – A specified number of days extending past the end of the Operating Horizon. For the Transmission Provider, the OASIS Planning Horizon is equal to the end of the Operating Horizon plus 3650 days.

1.11 Path Operator – That entity that is responsible for monitoring specified transfer paths, for conducting studies to determine the TTC for the specified transfer paths, and for disseminating information to those Transmission Providers who have contractual rights on that specified transfer path.

2. Description of Mathematical Algorithm Used to Calculate Firm and Non-Firm ATC

2.1 The Transmission Provider uses a rated path methodology in order to assess the firm and non-firm ATC for all posted paths in the Scheduling, Operating, and Planning Horizons. The methodology is based on the prescribed NERC Standard MOD-029-1

and is also in accordance with the Western Electric Coordinating Council's (WECC) rated path methodology. The process of calculating ATC is performed by a third-party software product that methodically calculates the firm and non-firm ATC in accordance with the mathematical algorithm detailed below.

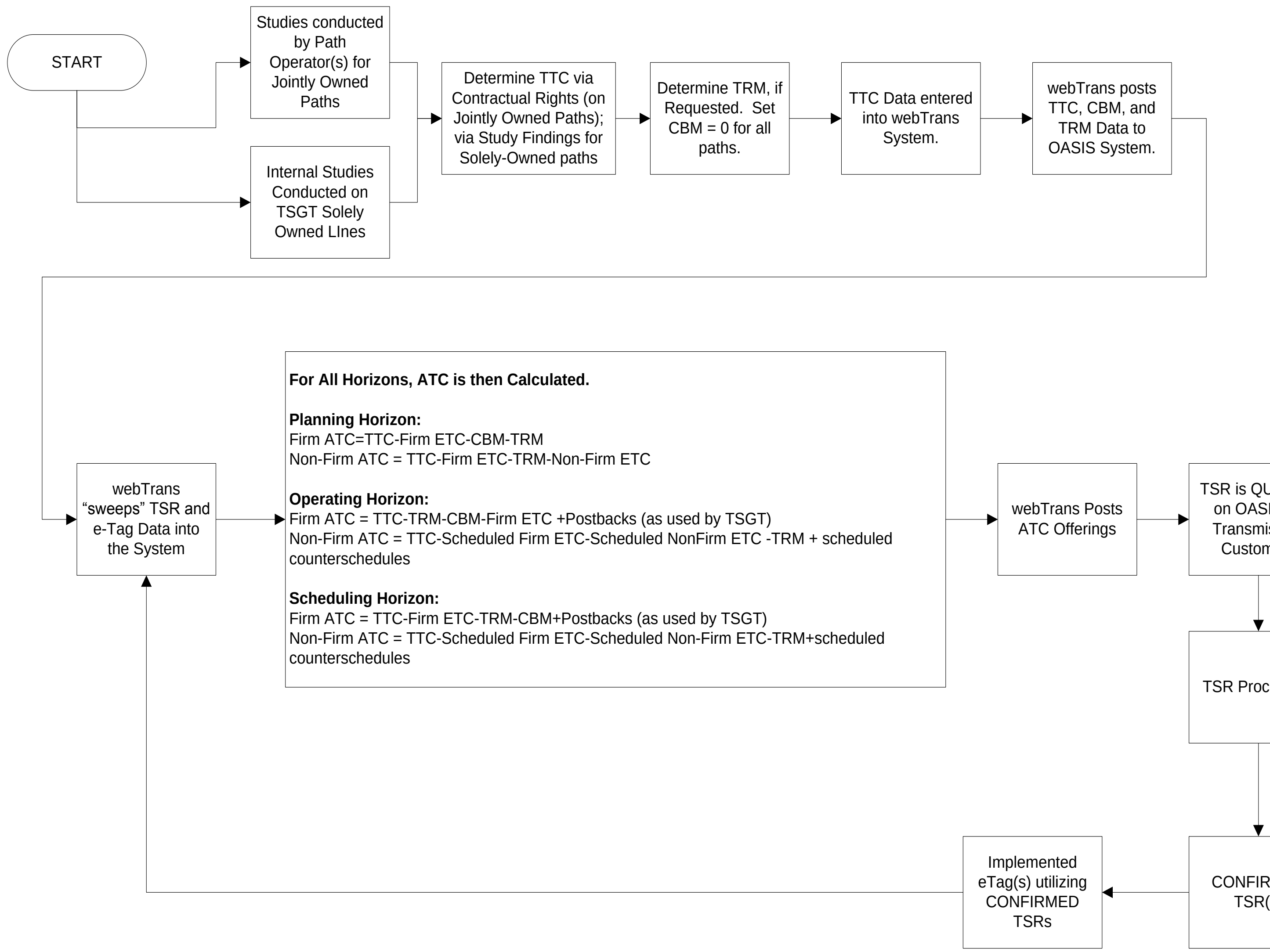
2.2 The mathematical algorithms used for firm and non-firm ATC in the Scheduling, Operating, and Planning Horizons are shown in the following general formulas:

ATCF=TTC – ETCF – CBM – TRM + PostbacksF + counterflowsF

ATCNF=TTC – ETCF – ETCNF – CBM – TRM + Postbacks + counterflows

Each component of the above formulas is further defined in the ATCID available on the Transmission Provider's main OASIS page at http://www.oasis.oati.com/TSGT, the details of which are also discussed in this Attachment C.

(3) Process Flow Diagram Illustrating the Various Steps Through Which ATC is Calculated



3. Process Flow Diagram Illustrating Various Steps Through Which ATC is Calculated

4. Description of How Each ATC Component is Calculated

4.1 Determination of Total Transfer Capability (TTC)

4.1.1 Calculation Methodology. The WECC Rated Paths using the MOD-029 rated path methodology on the Transmission Provider's transmission system include Path 30 (TOT1A), 31 (TOT2A), 36 (TOT3), 39 (TOT5), 47 (SNMI), and 48 (NNMI). The stated paths are operated by entities other than this Transmission Provider and as such, this Transmission Provider receives the TTC value from the Path Operator of these defined paths. The Transmission Provider posts its respective share of the path's TTC for each path for which this Transmission Provider has rights. For those paths that are owned by this Transmission Provider but which are not part of a jointly-owned path, the

Transmission Provider will utilize TTC values based upon the thermal facility ratings for all reliability-limited paths. If NERC MOD-29-1 requirement R2.1 simulation studies result in flow-limited transmission segments, then the TTC on the transmission segment will be set to that maximum simulation flow that satisfies all planning criteria.

(i) Once a determination of TTC is made, that TTC will normally remain fixed and will only change should there be a physical or operational change on the Transmission Provider's transmission system.

(ii) The Transmission Provider is party to several contractual agreements that allow for the Path Operator to allocate jointly-owned transmission capacity to the Transmission Provider. Because some of these paths have dynamic ratings, they are subject to frequent TTC changes as system conditions change. As the Transmission Provider receives TTC allocations from the Path Operator, the Transmission Provider will change the TTC postings in accordance with the Path Operator and in conjunction with an agreed upon allocation process by all path participants.

4.1.2 Databases Used in TTC Assessments. The power flow studies used in the Transmission Provider's TTC assessments are based on the system base case data developed through the Western Electric Coordinating Council (WECC).

4.1.3 Assumptions Used in TTC Assessments. The Path Operator(s) of the jointly-owned path(s) utilizes the MOD-029-1 Rated Path Methodology in conjunction with the system base case data developed through the WECC in determining the TTC for those paths.

4.2 Existing Transmission Commitments (ETC)

4.2.1 Calculation Methodology. Existing Transmission Commitments are divided into two categories, firm and non-firm, each having a subsequent impact on the calculation of firm or non-firm ATC.

4.2.1.1 Firm Existing Transmission Commitments (ETCF) measures the firm committed uses of the transmission system and includes the following:

(i) Firm Network Integration Transmission Service (NITSF) – Includes the capacity reserved for Network Integration Transmission Service to serve that customer's load. The Transmission Provider has determined the necessary commitments based on the Network Integration Service Customer's designated network resources and the designated loads to be served by those resources. For the majority of the Transmission Provider's paths, the TTC has been fully assigned to the various Network Integration Transmission Service customers. The Transmission Provider's system, relative to the Network Service load that must be served over the system, is such that even when designated Network Resources are off-line, the transfer capacity is still needed by the Network Customers so that they may continue to serve their respective loads from other resources.

(ii) Incorporation of Point-to-Point Transmission Service Requests (TSRs) – The Transmission Provider includes existing, confirmed TSRs for Point-to-Point transmission service in studies using the specified megawatt quantity granted as well as the specific Point of Receipt and Point of Delivery.

(iii) Incorporation of Rollover Rights (ROR) – The Transmission Provider accounts for the possibility that the eligible customer will choose to exercise their rollover rights.

Rollover rights obligations are shown on the OASIS under ATC Information.

(iv) Incorporation of Grandfathered (GF) Firm Transmission Service Agreements – The Transmission Provider includes the impact of agreements for transmission service that were executed prior to the effective date of FERC Order 888. The capacity value of the grandfathered firm transmission service agreement is the value used to derive the ETC.

4.2.1.2 NON-Firm Existing Transmission Commitments – Measures the non-firm use of the transmission system and includes the following components:

(i) Non-Firm Network Integration Transmission Service (NITSNF) – Includes capacity reserved on a non-firm basis by the Network Integration Transmission Service Customer. This transmission service is reserved directly by the customer and is reserved at the customer's discretion.

(ii) Incorporation of Non-Firm Point-to-Point Transmission Service Reservations (TSRs) – The Transmission Provider includes existing, confirmed TSRs in the non-firm ETC calculation.

4.3 Transmission Reliability Margin (TRM)

4.3.1 Practice. In Commission Order 890, the Commission notes the acceptable uses of TRM which includes the use for automatic sharing of reserves. The Transmission Provider allocated TRM for the use of automatic sharing of reserves and may change its policy on the use of TRM from time to time.

4.3.2 Calculation Methodology. The Transmission Provider works in conjunction with its Network Integration Transmission Service customers to utilize the

sharing matrices utilized by the respective reserve sharing groups to determine the megawatt amounts the customer is to provide in response to a contingency. The customer also determines with which Network Resources the customer will respond with. The response megawatt values, determined by the respective reserve sharing groups, are the values utilized to allocate TRM on the Transmission Provider's system.

4.3.3 Databases Used in TRM Assessments. No databases are utilized by the Transmission Provider to determine the TRM values. The Transmission Provider only the matrices developed by the respective reserve sharing groups.

4.3.4 Conditions Under Which the Transmission Provider Uses TRM. The Transmission Provider uses TRM to set aside capacity to deliver reserve obligations of its Network Integration Transmission Service customers. Generally, when a loss of a generation resource, which resides within the reserve sharing group's footprint, occurs the members of the reserve sharing group respond by delivering replacement energy to the member who experienced the loss. TRM is reserved to ensure sufficient transmission capacity exists to deliver the replacement energy requirement to the member experiencing the loss. As a contingency can occur at any time, the Transmission Provider does not release TRM for non-firm use, ensuring its availability for reserve activations.

4.4 Capacity Benefit Margin (CBM)

4.4.1 Practice. The Transmission Provider's practice does not allocate CBM on any posted path for any of the horizons. As the Transmission Provider does not utilize CBM, the value for CBM within any of the ATC calculations is set to zero (0) for all horizons.

Because the Transmission Provider does not set aside transfer capability for CBM and because no current regional methodology exists for the procurement of CBM, the Transmission Provider does not have any procedures for requesting CBM. Should the Transmission Provider determine the need to allocate CBM, the Transmission Provider will post the required information on its OASIS.

4.4.2 Calculation Methodology. The Transmission Provider does not allocate CBM and as such the CBM value in the ATC calculations is set to zero (0) for all posted paths for all horizons. The Transmission Provider will reevaluate the need for CBM annually.

4.4.3 Databases Used in CBM. As the Transmission Provider does not allocate CBM in its ATC calculation methodology, no databases are currently used in assessing CBM.

4.4.4 Demonstration of No-Double Counting of Contingency Outages When Performing CBM, TTC, and TRM Calculations. As the Transmission Provider does not allocate for CBM and because the value for CBM is set to zero (0) for all ATC calculation methodologies in all horizons, no double counting occurs.

4.4.5 Procedures to Allow the Use of CBM. NERC Standard MOD-004-1, R1 states that "The Transmission Provider that maintains CBM shall prepare and keep current a 'Capacity Benefit Margin Implementation Document' (CBMID)…." As The Transmission Provider does not maintain capacity for CBM, the Transmission Provider does not allow for a procedure to allow the use of CBM.

Proposed Date: 2019-09-21
Priority Order: 1020
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT D

Methodology for Completing a System Impact Study

Upon receipt of a valid request for service pursuant to the applicable terms and conditions of the Tariff, the Transmission Provider will perform a System Impact Study on a non-discriminatory basis for the requested transmission service. The study will employ Good Utility Practice, the engineering and operating principles, standards, guidelines, and criteria of the Transmission Provider, and applicable guidelines and standards established by the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and any entity (Authorized Entity) which has been authorized to promulgate or apply regional or national reliability planning standards (such as a regional transmission group), or any similar organization that may exist in the future of which the Transmission Provider is a member.

The Transmission Provider shall use its sole discretion as to the scope, details and methods used to perform the System Impact Study. However, at all times, the Transmission Provider will utilize methods and criteria consistent with those employed by the Transmission Provider for evaluating requirements for its member distribution cooperatives. Where possible, the Transmission Provider will utilize existing studies to evaluate new or upgraded service requests.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 1030
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT E

Index Of Point-To-Point Transmission Service Customers

See Transmission Provider's Electric Quarterly Report at the following Internet Address:

____

https://ferc.gov/docs-filing/eqr/q2-2013/data/spreadsheet.asp

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 1040
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT F

Service Agreement For
Network Integration Transmission Service

1.0 This Service Agreement, dated __________ is entered into by and between Tri-State Generation and Transmission Association, Inc. (Transmission Provider) and __________ (Transmission Customer).

2.0 Transmission Customer has been determined by Transmission Provider to have a Completed Application for Network Integration Transmission Service under the Tariff.

3.0 Transmission Customer has provided Transmission Provider a deposit in accordance with the provisions of Section 29.2 of the Tariff.

4.0 Transmission Customer and Transmission Provider have completed all necessary technical arrangements in accordance with the provisions of Sections 29.3 and 29.4 of the Tariff.

5.0 Transmission Customer has executed a Network Operating Agreement with Transmission Provider in accordance with Section 35.2 of the Tariff.

6.0 Network Integration Transmission Service under this Service Agreement shall commence on the later of: (1) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Network Integration Transmission Service under this Service Agreement shall terminate as stated in Section 1 of the Specifications to this Service Agreement.

7.0 Transmission Provider agrees to provide and Transmission Customer agrees to

take and pay for Network Integration Transmission Service in accordance with the provisions of Part III of the Tariff as it may be amended and this Service Agreement.

8.0 Any notice or request made to or by either party regarding this Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Provider:
Tri-State Generation and Transmission Assoc., Inc.
OASIS/OATT Administrator
Direct Mail and Overnight Mail: 1100 W. 116th Ave., Westminster, CO 80234 or via email at OATTAdmin@tristategt.org

Transmission Customer:

____
____
____
____
____

9.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the parties have caused this Service Agreement to be executed by their respective authorized officials as of the date indicated below.

Transmission Provider:

By: _______________________________

Name: __________________________________

Title: _____________________________

Date: _____________________________

Transmission Customer:

By: _______________________________

Name: ________________________________

Title: ____________________________

Date: ____________________________

Specifications for
Network Integration Transmission Service

1.0 Term of Network Integration Transmission Service: ________________________
Start Date: ____
Termination Date: ____

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates. Transmission Provider shall accept power and energy scheduled by Transmission Customer or its designated scheduling agent from Transmission Customer's Network Resources at the Point(s) of Receipt indicated in Section 3.0 below.

____

3.0 Network Resources:
____
____
____
____
Total Network Resources: ______________________________________

4.0 Network Loads:
____
____
____
____
Total Network Loads: ______________________________________

5.0 Designation of party(ies) subject to reciprocal service obligation:
____

____

____

6.0 Name of any intervening systems providing transmission service:

____

____

____

7.0 Network Integration Transmission Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff).

7.1 Load Ratio Share of Annual Transmission Revenue Requirement as determined pursuant to Section 34 of the Tariff.

7.1.1 For the first twelve months of Network Integration Transmission Service under this Service Agreement commencing on the Start Date set forth in Section 1 of the Specifications, Transmission Customer's Load Ratio Share will be determined based on Transmission Customer's average Load Ratio Share in the months in which Transmission Customer has taken Network Integration Transmission Service. After the first twelve months of Network Integration Transmission Service, Load Ratio Share will be calculated on a rolling twelve month average basis.

7.2 System Impact Study and/or Facilities Study charge(s):

____

7.3 Direct Assignment Facilities charge:

____

7.4 Ancillary Services charges:

ATTACHMENT G

Network Operating Agreement

[**Note:** It may be necessary to include additional provisions or revise the provisions of this Network Operating Agreement to take into account the particular circumstances of a Network Customer. Transmission Provider reserves the right to modify this form of Network Operating Agreement for individual Transmission Customers.]

Tri-State Generation and Transmission Association, Inc. (Transmission Provider) and ______________________(Transmission Customer) agree that the provisions of this Network Operating Agreement (NOA), dated _______________and the Parties' Service Agreement for Network Integration Transmission Service dated ________________ (Service Agreement) govern the transmission service to the Transmission Customer in accordance with the Transmission Provider's Open Access Transmission Tariff (Tariff). Unless specified herein, capitalized terms shall refer to the terms defined in the Tariff.

1.0 Character of Service

Power and energy delivered under the Service Agreement and this NOA shall be delivered as three-phase alternating current at a frequency of approximately sixty (60) Hertz, and at the nominal voltages at the Point(s) of Delivery (POD) and Point(s) of Receipt as specified in the Service Agreement.

2.0 Balancing Authority Area Requirements

(a) Neither the Transmission Provider nor the Transmission Customer is a Balancing Authority Area (referred to and defined as "Control Area" in the Tariff). The Transmission Customer shall satisfy its requirements, including all Ancillary Services not procured from the Transmission Provider nor self-provided, by contracting with another entity that can satisfy those requirements in a manner that is consistent with Good Utility Practice and satisfies NERC and WECC standards.

(b) The Transmission Customer shall report all existing and future Generation Source(s) (defined in Section 6 of this NOA) connected to its system to the Transmission Provider and the Balancing Authority Area operator. The Transmission Customer shall report all planned Generation Source(s) with as much notice as practical to the Transmission Provider and the Balancing Authority Area operator. The Transmission Customer shall report the type of generation installed or to be installed, the total name plate rating of the generation to be installed and the electrical location of where the generation is installed or will be installed. Transmission Customer agrees to telemeter in real time all generation to the Transmission Provider and the Balancing Authority Area operator in a format acceptable to the parties.

(c) If the Balancing Authority Area sets forth any other requirements either on the Transmission Provider or the Transmission Customer as a result of the Transmission Customers transmission service under this NOA, all costs associated with complying with those requirements will be the responsibility of the Transmission Customer.

(d) The Transmission Customer and the Transmission Provider shall plan, construct, operate, and maintain their respective facilities and system in accordance with Good Utility Practice, which shall include, but not be limited to, all applicable guidelines of NERC and WECC, as they may be modified from time to time, and any generally accepted practices in the region.

3.0 Operating Requirements

(a) The Transmission Customer shall operate its existing and future Generation Sources in a manner consistent with that of the Transmission Provider, including following voltage schedules, providing governor response, meeting power factor requirements at the point of interconnection with the Transmission System, and other such criteria required by NERC and WECC and/or consistently adhered to by the Transmission Provider and in a manner consistent with Good Utility Practice and applicable law.

(b) Insofar as practicable, the Transmission Provider and the Transmission Customer shall protect, operate, and maintain their respective systems so as to avoid or minimize the likelihood of disturbances that might cause impairment of service on the system of the other.

4.0 Redispatch and Curtailment

If the Transmission Provider determines that redispatching resources or curtailing resources to relieve an existing or potential transmission system constraint is the most effective way to ensure the reliable operation of the Transmission System, the resources of the Transmission Provider and the Transmission Customer will be redispatched or curtailed without regard to the ownership of such resources. The Transmission Provider will apprise the Transmission Customer of its redispatch and curtailment practices and procedures, as they may be modified from time to time.

5.0 Load Shedding and Load Shedding Equipment

(a) The Parties shall implement and maintain load shedding programs to maintain the reliability and integrity of the Transmission System, as provided in Section 33.6 of the Tariff. Load shedding shall include: (1) automatic load shedding by underfrequency and/or undervoltage relay and (2) manual load shedding. The Transmission Provider will order load shedding to maintain the relative sizes of load served, unless otherwise required by circumstances beyond the reasonable control of the Transmission Provider. Automatic load shedding devices will operate without notice. However, when manual load shedding is necessary, the Transmission Provider shall notify the Transmission Customer's dispatchers or schedulers of the required

action and the Transmission Customer shall comply immediately.

(b) The Transmission Customer shall, at its own expense, provide, operate, and maintain in service high-speed, digital underfrequency and/or undervoltage load shedding equipment. The Transmission Customer will install underfrequency and/or undervoltage relays as necessary in a manner consistent with the Transmission Provider's existing coordinated Under Frequency Load Shedding Program and Under Voltage Load Shedding schemes when applicable in compliance with any applicable NERC and WECC requirements. If the Transmission Customer also has obligations under any NERC and WECC requirements and has not contractually delegated those responsibilities to the Transmission Provider, the Transmission Customer shall be responsible for all costs associated to provide, operate, and maintain in service the Transmission Customer's load shedding equipment in accordance with the applicable requirements.

(c) In the event the Transmission Provider modifies its load shedding program, the Transmission Customer shall, at its expense, make all necessary changes to its automatic and manual load shedding (as applicable) equipment and the settings of such equipment. The Transmission Provider may request a test of the Transmission Customer's load shedding equipment with reasonable notice.

(d) In the event that the Transmission Customer fails to shed load in accordance with this Section 5, the Transmission Customer shall be charged in accordance with the Tariff. Continued failure to comply with the load shedding requirements of this Section 5 may also result in termination of this NOA and the Service Agreement.

6.0 Metering

(a) Meter Ownership, Operation and Maintenance Responsibilities.

i. All metering and associated metering equipment for this NOA shall conform to Good Utility Practice and the standards and practices for the Balancing Authority Area(s).

ii. POD Meters: The Transmission Provider owns and, at no expense to the Transmission Customer, is responsible for operation, maintenance, repair, and replacement of the following POD meters and associated metering equipment

(POD Meters):

iii. Generation Source Meters: The Transmission Customer, at no expense to the Transmission Provider, shall own, procure, install, operate, maintain, repair, and replace meters and communication for all Transmission Customer's generating resources (including any generating resources located behind the POD for which the Transmission Customer takes title to or is deemed to take title to the energy of such generating resource) located behind the POD (Generation Source(s)), including meters currently existing at the Solar Sites (defined in Section 7 of this NOA) and meters installed on all future Generation Source(s)(these meters collectively are referred to as "Generation Source(s) Meters").

1) At least sixty (60) calendar days in advance of operation of any new Generation Source(s) on the Transmission Customer's system, the Transmission Customer shall notify the Transmission Provider of any new Generation Source(s) used to serve the Transmission Customer's Network Load.

iv. Network Resource Meters: The Transmission Customer, at no expense to the Transmission Provider, shall own, procure, install, operate, maintain, repair, and replace meters and communication at all Network Resources used to serve the Transmission Customer's Network Load.

(b) Losses.

Electric capacity and energy delivered to the Transmission Customer's Network Load by the Transmission Provider will be measured by meters installed at the POD for such Network Load.

(c) Meter Data.

i. POD Meters.

1) The Transmission Provider will read the POD Meters remotely.

2) Transmission Provider shall make available, and Transmission Customer

authorizes Transmission Provider to provide, revenue quality data on a real time basis necessary to determine Transmission Customer's Network Load to the Balancing Authority and to other transmission providers as necessary.

3) The Transmission Customer shall support the Transmission Provider's ability to read such meters remotely.

4) If at any time the Transmission Provider is unable to remotely read the POD Meters, and the issue causing the Transmission Provider's inability to read such meters is within the Transmission Customer's ability to resolve and the Transmission Customer fails to resolve such issue, Transmission Provider shall invoice the Transmission Customer based on the Transmission Customer's peak load provided in the data furnished under Section 9.b for the period under which Transmission Provider was unable to read such meters.

5) Transmission Provider's meter data information for the POD Meters will remain available to the Transmission Customer for three (3) years after the date of the meter reading.

ii. <u>Generation Source(s) Meters</u>.

1) Transmission Customer grants to the Transmission Provider the right to remotely read Transmission Customer's Generation Source(s) Meters located behind the POD and pursuant to Section 7 of this NOA, interrogate Transmission Customer's existing and any new generation remote terminal units (RTUs).

2) Transmission Customer will provide to Transmission Provider meter data information for any Generation Source(s) Meters not equipped to remotely read such informationon a monthly basis no later than the 8th of every month. Should the 8th fall on a Saturday or Sunday or a holiday, the Generation Meter Data shall be submitted to the Transmission Provider no later than the first weekday prior to the 8th.

3) Generation reflected in the Transmission Customer's Generation Source(s) Meters will be added to the POD Meters (as adjusted for losses pursuant to Section 6.b) to determine Transmission Customer total monthly Network Load pursuant to Section 34 of the Tariff.

4) If at any time the Transmission Provider is unable to remotely read Transmission Customer's Generation Source(s) Meters or unable to interrogate Transmission Customer's generation RTUs, Transmission Provider may, at its sole discretion, include in the Transmission Customer's monthly invoice for Network Integrated Transmission Service the full name plate capability of the Transmission Customers Generation Source(s), regardless if the Generation Source(s)was on line until reliable telecommunications facilities are provided and Transmission Provider is able to remotely read Transmission Customer's Generation Source(s) Meters and able to interrogate Transmission Customer's generation RTUs.

5) Transmission Customer's meter data information for the Generation Source(s) Meters will remain available to the Transmission Provider for three (3) years after the date of the meter reading.

(d) Meter Testing.

i. At the Transmission Customer's expense, the Generation Source(s) Meters will be tested at least annually by the Transmission Customer. Representatives of the Transmission Provider will be afforded an opportunity to witness such tests. In the event the test shows the meter to be inaccurate, the Transmission Customer will make any necessary adjustments, repairs or replacements thereon.

ii. At the Transmission Customer's expense, the Transmission Provider will, upon request of the Transmission Customer but not more than twice annually, test any POD Meters used for determining the receipt or delivery of capacity and energy by the Transmission Provider. In the event the test shows the meter to be inaccurate, the Transmission Provider will make any necessary adjustments, repairs or replacements thereon.

iii. In the event any meter used to measure capacity and energy fails to register or is found to be inaccurate, appropriate billing adjustments will be made based on the best information available. An inaccurate meter is one that exceeds one percent (1%) plus or minus of the calibrated standard. If, as a result of any test, a meter is found to register in excess of one percent (1%) either above or below normal, then the reading of such meter previously taken will be corrected according to the percentage of inaccuracy so found, but no correction will extend beyond ninety (90) calendar days previous to the day on which the inaccuracy is discovered by such test.

(e) Meter Access:

i. In the event that any of the POD Meters are located within or attached to the Transmission Customer's equipment, the Transmission Customer grants the right for such arrangement to the Transmission Provider, or its employees, agents and contractors, and grants access to the POD Meters at all reasonable hours and for any reasonable purpose, including but not limited to testing, maintenance, repair, replacement of the metering equipment and associated communication equipment.

ii. The Transmission Customer grants to the Transmission Provider, its employees, agents, and contractors, a non-exclusive license to install, operate, maintain, repair, replace, and test the Transmission Provider's equipment.

iii. Should the Transmission Provider desire to witness the testing of the Generation Source(s) Meters located behind the POD pursuant to Section 6.d.i. of this NOA, the Transmission Customer permits the Transmission Provider access to such meters at all reasonable hours.

(f) Check Meters:

The Transmission Customer has the right, at its expense to install suitable metering equipment at any POD, as herein provided for the purpose of checking the meters installed by the Transmission Provider.

7.0 Operational Information

The Transmission Customer shall provide data to the Transmission Provider that is needed for the safe and reliable operation of the Transmission Customer's and the Balancing Authority Area(s) and to implement the provisions of the Tariff.

(a) By September 1st of each year, the Transmission Customer shall provide its Network Resource availability forecast, including all Transmission Customer's Generation Source(s) (e.g., all planned resource outages, including off-line and on-line dates) for the following year to the Transmission Provider. Such forecast shall be made in accordance with Good Utility Practice. The Transmission Customer shall inform the Transmission Provider, in a timely manner, of any changes to the Transmission Customer's Network Resource availability forecast. In the event that the Transmission Provider determines that such forecast cannot be accommodated due to a transmission constraint on the Transmission System, or that such forecast may jeopardize the reliability of the Transmission Provider's system, the provisions of Section 33 of the Tariff will be implemented.

(b) At least 48 hours in advance of the beginning of every calendar day, the Transmission Customer shall provide its best forecast of any planned transmission or Network Resource outage(s) and other operating information that would assist the Transmission Provider in the reliable operation of the Balancing Authority Area(s). In the event that such planned outages cannot be accommodated due to a transmission constraint on the Transmission Provider's Transmission System, the provisions of Section 33 of the Tariff will be implemented.

(c) The Transmission Provider and the Transmission Customer shall notify and coordinate with the other party prior to the commencement of any work by either party (or contractors or agents performing on work their behalf), which work may directly or indirectly have an adverse effect on the Balancing Authority Area(s) of the other party.

(d) The Transmission Provider has established a Network Operating Committee (Committee) for all of the Transmission Provider's Network Customers in order to coordinate operating criteria for the Parties' respective responsibilities under their Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

8.0 Network Planning

(a) To protect the integrity of the transmission systems, the Transmission Customer shall not connect or allow any third-party to connect an electric generating facility to the Transmission Provider's or the Transmission Customer's transmission or distribution system ("Proposed Interconnection") until the Transmission Customer and Transmission Provider have studied, or have reviewed the other Party's study,

assessing the impacts of the Proposed Interconnection on the Parties' transmission and distribution systems. Any Proposed Interconnection shall be consistent with: 1) Transmission Provider's Tariff; 2) any applicable NERC requirements; and 3) facility interconnection requirements as may be required by Transmission Provider, Transmission Customer, or a third party, as applicable. Any required mitigation methods identified in the studies shall be agreed to among the applicable parties prior to such connection.

(b) In order for the Transmission Provider to plan, on an ongoing basis, to meet the Transmission Customer's requirements for Network Integration Transmission Service, the Transmission Customer shall provide, by September 1st of each year, updated information (current year and 10-year projection) for Network Load and Network Resources including all Transmission Customer's Generation Source(s), any other information reasonably necessary to plan for Network Load and Network Resources, and any other information reasonably necessary to plan for Network Integration Transmission Service. This type of information is consistent with the Transmission Provider's information requirements for planning to serve Native Load Customers. The data will be provided in a format consistent with that used by the Transmission Provider.

9.0 Transfer of Power and Energy Through Other Systems

Since the Transmission System is, and will be, directly or indirectly connected with other electric systems, it is recognized that, because of the physical and electrical characteristics of the facilities involved, power delivered under the Service Agreement and this NOA may flow through such other systems. The Parties agree to advise other operators of electric systems as deemed appropriate of scheduled transfers and to maintain good relationships with affected third parties.

10.0 Dispute Resolution

Any dispute among the Parties regarding this NOA shall be resolved pursuant to Section 12 of the Tariff, or otherwise, as mutually agreed by the Parties.

11.0 Notice

Any notice or request made to or by either Party regarding this NOA shall be made to the representative of the other Party as indicated in the Service Agreement.

12.0 Incorporation

The Tariff and the Service Agreement are incorporated herein and made a part hereof.

13.0 Term

The term of this NOA shall be concurrent with the term of the Service Agreement between the Parties.

14.0 Severability

In the event that any of the terms, covenants or conditions of this NOA, its exhibits, or the application of any such term, covenant, or condition shall be held invalid by any court or administrative body having jurisdiction, it is the intention of the Parties that in lieu of each such term, covenant or condition that is invalid, there be added as part of this NOA, a valid term, covenant, or condition as similar in terms as possible to such invalid term, covenant or condition. The other terms of this NOA shall not be affected by a holding that any term hereof is invalid; and they shall remain in full force and effect notwithstanding any such holding.

15.0 Amendments

This NOA may be amended, changed, modified or altered, provided that such amendment, change, modification or alteration shall be in writing and signed by both Parties.

16.0 Governing Law

Except as governed by federal law, this NOA shall be governed by and construed in accordance with internal laws of the State of Colorado, without giving effect to any choice or conflict of law provision or rule (whether of the State of Colorado or any other jurisdiction) that would cause the application of laws of any jurisdiction other than those of the State of Colorado.

17.0 Liability

Neither Party and its directors, officers, employees or agents shall be liable for any loss of earnings, revenues, indirect or consequential damages or injury which may occur to the other Party as a result of outages in delivery of service hereunder.

IN WITNESS WHEREOF, the parties have caused this NOA to be executed by their respective authorized officials.

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

By:

Name　　　　Title　　　　Date

NETWORK CUSTOMER.

By: __________

Name Title Date

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 1060
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT H

Annual Transmission Revenue Requirement For Network Integration Transmission Service

The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be calculated using the Transmission Provider’s Formula Rate Template set forth in Attachment M of this Tariff. The results of the formula calculation shall be posted on the Transmission Provider’s OASIS in accordance with the Implementation Protocols. The Annual Transmission Revenue Requirement will be as identified on the Rates tab of the Transmission Provider’ s Formula Rate Template. 6. FERC Annual Charge Fee recovery: An administrative charge shall be applied to all transmission services taken from Transmission Provider to recover the cost of the Commission annual charge (Annual Charge) under Part 382 of the Commission's

regulations. The Commission issues the invoice for the Annual Charge to Transmission Provider based on its megawatt-hours (MWH) of transmission of electric energy in interstate commerce as reported under the FERC Reporting Requirement 582. The charge factor or billing rate for Transmission Provider is calculated by the Commission on its Annual Charge invoice and is identified on the Rates tab of the Transmission Provider's Formula Rate Template posted on the Transmission Provider's OASIS. Transmission Provider shall file the posted Annual Charge with the Commission, as part of its annual informational filing. The posted Annual Charge billing rate shall then be billed for all MWH of transmission service to the individual Transmission Customer during each Formula Rate year.

No Transmission Customer shall request that the Annual Charge billing rates be placed into effect subject to suspension or refund or that the Commission otherwise condition recovery of such FERC Annual Charge. However, each such Transmission Customer reserves its rights, if any, to challenge, or seek refunds concerning any such FERC Annual Charge to the extent such FERC Annual Charge does not reflect a simple and accurate pass-through of the FERC Annual Charge.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 1070
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT I

Index Of Network Integration Transmission Service Customers

See Transmission Provider's Electric Quarterly Report at the following Internet Address:

https://ferc.gov/docs-filing/eqr/q2-2013/data/spreadsheet.asp

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 1080
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT J

Procedures for Addressing Parallel Flows

Transmission Provider shall implement curtailment of transmission service in accordance with Western Electricity Coordinating Council (WECC) Standard IRO-STD-006-2, Qualified Path Unscheduled Flow Relief, or successor regional standard approved by the Commission.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 1090
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT K

Transmission Planning Process

I. Overview of Tri-State Transmission Planning Process

Tri-State Generation and Transmission Association, Inc. (Tri-State) is an electric power cooperative operating on a not-for-profit basis that generates and transmits electricity to its member rural electric cooperatives and public power districts in Colorado, Nebraska, New Mexico and Wyoming. Tri-State is a public utility that provides Point-to-Point (PTP) and Network Integration Transmission Service (NITS) under an Open Access Transmission Tariff (OATT or Tariff).

Tri-State's transmission planning process is based on the following three core objectives:

- Maintain safe, reliable, affordable, and responsible electric service to its members, consistent with its obligations under federal and state law.

- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to the transmission facilities under its control.

- Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent and participatory manner.

Tri-State's transmission planning process is intended to facilitate the timely and coordinated development of transmission infrastructure that both maintains system reliability and meets Transmission Customer needs, while continuing to provide reliable, affordable, and responsible electric power to its members.

The Tri-State planning process includes an annual open planning meeting to permit all interested parties, including NITS and PTP Transmission Customers, interconnecting neighboring transmission providers, regulatory agencies, and all other stakeholders, to provide input into and comment on Tri-State's transmission plan.

Tri-State coordinates its planning process with other transmission providers and stakeholders at the regional and subregional levels of the Western Interconnection through its active participation in the Colorado Coordinated Planning Group (CCPG), the Southwest Area Transmission Planning (SWAT) group, membership in WestConnect, and membership in the Western Electricity Coordinating Council (WECC).

Three subregional planning groups operate within the WestConnect footprint: the Colorado Coordinated Planning Group (CCPG), the Southwest Area Transmission Planning (SWAT) group and the Sierra Coordinated Planning Group (Sierra). WestConnect's planning effort, which includes funding, planning management, analysis, report writing and communication services, supports and manages the coordination of the subregional planning groups and their respective studies. These responsibilities are detailed in the WestConnect Project Agreement for Subregional Transmission Planning (the WestConnect STP Project Agreement) dated May 23, 2007. A copy of the STP Project Agreement is available at www.westconnect.com. Tri-State is a signatory to the WestConnect Project Agreement.

The subregional planning groups within the WestConnect footprint, assisted by the WestConnect planning manager, coordinate with other Western Interconnection transmission providers and their subregional planning groups as explained in section III of this document.

II. Tri-State Local Transmission Planning

Participation in Tri-State's local planning process is open to all interested parties, including but not limited to, all NITS and PTP Transmission Customers, interconnecting neighboring transmission providers, regulatory agencies, and other stakeholders.

A. General Provisions for Tri-State Local Transmission Planning Process

1. Purpose of Local Transmission Planning Studies

   Tri-State's local transmission planning process is designed to meet the following needs:

   a. Provide adequate transmission to access sufficient resources in order to reliably and economically serve Tri-State's member and other Transmission Customer's loads.

   b. Support Tri-State's members' sub-transmission and distribution

      systems.

   c. Provide for interconnection of new generation resources.

   d. Coordinate new interconnections with other transmission systems.

   e. Accommodate requests for long-term transmission access.

   f. Consider local transmission needs for economic upgrades to address congestion.

   g. Consider local transmission needs driven by Public Policy

      Requirements.

2. Types of Local Transmission Planning Studies

   a. *Local Reliability Studies*. Tri-State will conduct reliability studies to

ensure that all NERC, WECC, and local reliability standards are met for each year of the ten-year planning horizon, including all Transmission Customer-planned loads and resources. These reliability studies will be coordinated with the other regional transmission planning organizations through the CCPG, WestConnect, and WECC study efforts.

b. *Generator Interconnection Studies*. Tri-State will perform, or cause to be performed, system interconnection studies at the request of an Interconnection Customer under the terms and conditions specified in the Large Generator Interconnection Procedures (LGIP) and Small Generator Interconnection Procedures (SGIP) of Tri-State's OATT.

c. *Economic Studies*.
The purpose of economic planning studies is to identify significant and recurring congestion on Tri-State's transmission system and/or address the integration of new resources and/or loads. Such studies may analyze any, or all, of the following: (i) the location and magnitude of the congestion, (ii) possible remedies for the elimination of the congestion, (iii) the associated costs of congestion, (iv) the costs associated with relieving congestion through system enhancements (or other means), and, as appropriate (v) the economic impacts of integrating new resources or/and loads.

d. *Public Policy Requirements.* For purposes of this Attachment K, "Public Policy Requirements" means those requirements enacted by state or federal laws or regulations, including those enacted by local governmental entities, such as a municipality or county. Public Policy Requirements, as applicable, are incorporated into the load and resource forecasts provided by Transmission Customers and/or are modeled in the local planning studies.

3. Confidential or Proprietary Information

Tri-State's transmission planning studies may include base case data that are WECC proprietary data or classified as Critical Energy Infrastructure Information ("CEII") by the Federal Energy Regulatory Commission ("FERC" or "Commission"). Tri-State maintains base power flow, stability and short circuit databases, including all underlying assumptions, and contingency lists on a password-protected website, subject to confidentiality provisions. Such network models and underlying assumptions reasonably represent current system conditions. Stakeholders are required to sign a confidentiality agreement prior to the release of commercially sensitive information or CEII.

A Stakeholder must also hold membership in, or execute a non-disclosure agreement with, WECC in order to obtain requested base case data from Tri-State. Tri-State will not provide confidential information belonging to third parties without obtaining the consent of the third parties.

4. Transmission Planning Cycle

Tri-State conducts its transmission planning on a calendar year cycle for a ten-year planning horizon. Tri-State updates its ten-year plan annually and provides summaries of its transmission plans at Stakeholder meetings. The ten-year plan results are summarized in the WestConnect Annual Ten-Year Transmission Plan, which is posted to the WestConnect website. In addition, Tri-State files a listing of significant projects with the Colorado Public Utilities Commission at the end of April each year as required by Rule 3206. Tri-State also biennially files a summary of its transmission plans for the state of Colorado in accordance with the requirements of the Colorado Public Utilities Commission Rule 3627.

5. Transmission Customer's Responsibility for Providing Data

a. *Use of Customer Data*. Tri-State uses the information provided by its Transmission Customers to, among other things, assess network loads and resources, identify transmission needs and operating dates, and to update regional models used to conduct planning studies.

b. *Submission of Data by NITS Customers*. Pursuant to Tri-State's OATT, NITS Transmission Customers are required to submit ten-year projected loads and resources to Tri-State on an annual basis. Such information is to be submitted by October 1st of each year to be included in the following year's planning process.

c. *Submission of Data by Other Transmission Customers*. In order to provide the most accurate planning models, it is essential that all other Transmission Customers provide their ten-year load and resource needs for inclusion in the Tri-State transmission planning process. This information must be submitted by October 1st of each year in order to be included in the following year's planning process.

d. *Transmission Customer Data to be Submitted*. To the maximum extent practical and consistent with protection of proprietary or confidential information, data submitted by Network and Point-to-Point Transmission Customers and other Transmission Customers shall include the following information for the ten-year planning horizon:

i. Generators – planned additions or upgrades (including status and expected in-service dates), planned retirements and any environmental restrictions.

ii. Demand response resources – existing and planned demand response resources and their impacts on demand and peak demand.

iii. Network Transmission Customers – forecast information for load and resource requirements over the planning horizon and identification of demand response reductions. Forecast information shall address Public Policy Requirements.

iv. Point-to-Point Transmission Customers – projections of need for service, including transmission capacity, duration of service and points of receipt and delivery.

Each Transmission Customer is responsible for submitting timely written notice to Tri-State of material changes in any of the information previously provided related to the Transmission Customer's load, resources, or other aspects of its facilities or operations which may, directly or indirectly, affect Tri- State's ability to provide service.

6. Stakeholder Participation and Public Meetings

a. Purpose and Scope

Tri-State performs transmission planning-related stakeholder outreach as a standard part of its day-to-day business consistent with its policy of planning in an open, coordinated, transparent and participatory manner. This outreach encompasses various efforts including: Colorado Public Utilities Commission Rule 3627 specific meetings and stakeholder communications; FERC Order No. 890 specific meetings and communications; project-specific meetings and communications; and CCPG participation.

In addition to larger stakeholder meetings addressing system-wide transmission projects, Tri-State also conducts a number of meetings related to individual proposed transmission projects. These meetings and other project-related communications include relevant government agencies, economic development entities, and other interested organizations and persons to inform them of the proposed project and

provide an opportunity for feedback and consideration of potential alternatives. The nature and timing of outreach efforts related to specific projects is generally dependent on the development status of the project.

Details of Tri-State's larger stakeholder meetings, including invitation lists, attendees, questions and comments received together with Tri-State's responses thereto, and relevant presentations can be found on the Tri-State company website.

Tri-State will conduct at least one open public planning meeting each year that will allow stakeholders to participate in Tri-State's transmission planning process. The public transmission planning meetings will be open to all stakeholders. The meetings will provide an open, transparent forum whereby electric transmission stakeholders can comment and provide input to Tri-State during the transmission planning process. These public transmission planning meetings will serve to:

i. Promote discussion of all aspects of the Tri-State transmission planning activities, including, but not limited to, methodology, study inputs, public policy requirements, study results, and alternative solutions.

ii. Provide a forum for Tri-State to better understand the specific electric transmission interests of all stakeholders.

b. <u>Public Meeting Process</u>

At such meetings Tri-State shall: (a) review its transmission planning process and current study plan with stakeholders; (b) receive transmission study requests from stakeholders for review and discussion; (c) solicit information from its Transmission Customers on loads and resources and other needs, such as public policy requirements, for the preparation of its ten-year plan; and (d) provide updates on its planned projects.

c. <u>Meeting Notices, Documents, and Communications</u>

Stakeholders include federal, state, county, and municipal government agencies as well as other non-governmental organizations and

individuals having an interest in the transmission planning process. Tri-State identifies potential governmental stakeholders based generally on a five-mile area surrounding proposed transmission facilities. Federal agencies in the areas of the transmission projects typically included in Tri-State's Transmission Plan are the Bureau of Land Management, the U.S. Forest Service, the National Park Service, and the Department of Defense. Potentially interested state agencies include the Colorado State Land Board and associated Stewardship Trust Lands, and the Colorado Division of Parks and Wildlife. Outreach to county and local governments typically includes communications to relevant elected officials as well as administrators, managers, and land planning, economic development, and legal staffs. In some instances, Tri-State's governmental outreach will include agencies such as parks and school districts.

Contact lists for non-governmental stakeholders are developed through various transmission planning forums such as CCPG and other WestConnect planning groups, as well individuals and organizations that have participated in previous Tri-State stakeholder meetings. When known, Tri-State also includes stakeholders identified as being interested in specific proposed projects. The resulting non-governmental stakeholders includes other utilities, Tri-State members, energy and transmission project developers, environmental groups, economic development organizations, various advocacy groups, and elected officials not already included in the governmental outreach communications.

Meeting notices, including date, time, place and meeting agenda, will be posted on the Tri-State company website as well as the WestConnect website. **Error! Hyperlink reference not valid.**Tri-State will establish and post its public planning meeting schedule at least once annually.

The agendas for Tri-State's public planning meetings will be sufficiently detailed, posted on the Tri-State company website, the WestConnect website, and circulated to its distribution list in advance of the meetings in order to allow Transmission Customers and stakeholders the ability to choose their meeting attendance most efficiently.

Tri-State will post all meeting-related notes, documents and drafts or final reports on its company website.

7. Planning Criteria, Methodology, and Planning Study Results

Tri-State's engineering methodologies and criteria used in planning its transmission system are documented in Tri-State's Engineering Standards Bulletin, which can be found on the Tri-State company website as well as OASIS.

Tri-State's biennial 10-year transmission plan filed with the Colorado PUC in accordance with Rule 3627 is posted on the company website as well.

8. Comparability and Evaluation of Alternative Solutions

Tri-State recognizes that its Transmission Customers need to address transmission system requirements to meet Reliability Standards, Public Policy Requirements, which include state renewable portfolio/carbon reduction standards or goals, state resource adequacy and demand response requirements, and other similar regulatory programs that could include treatment of customer demand response resources. Tri-State shall consider verified demand response, if available, when evaluating transmission project alternatives in the local study planning process. Tri-State shall consider alternative solutions to address these needs from sponsors of transmission, generation and demand resources. In particular, alternative solutions shall be evaluated against each other based on a comparison of their effectiveness of performance and relative economics. In evaluating alternatives, including demand responses and transmission alternatives, Tri-State shall evaluate alternatives on the basis of: (1) ability to mitigate any criteria or NERC Reliability Standard issues; (2) ability to mitigate those issues over the time frames of the study; (3) comparison of the capital costs of the demand response, as compared to other transmission alternatives; (4) the technical, financial and operational feasibility of any proposed alternatives; and (5) comparison of any operational benefits or issues between demand responses or transmission alternatives. From this comparison, the most appropriate project alternative can be selected.

B. Local Reliability Transmission Planning Study Process

Tri-State's transmission planning process is intended to facilitate the timely and coordinated development of transmission infrastructure that maintains system reliability and meets Transmission Customer needs, while continuing to provide reliable, affordable, and responsible electric power to its members.

In this regard, the primary objectives of Tri-State's transmission planning process are to meet the needs of Network and Point-to-Point Transmission Customers, maintain reliability, accommodate load growth, and coordinate interconnections. The key elements

of Tri-State's transmission planning process are:

- Maintaining safe, reliable, affordable, and responsible electric service to its members
- Improving efficiency of electric system operations
- Providing open and non-discriminatory access to its transmission facilities
- Planning new transmission infrastructure in a coordinated, open, transparent and participatory manner

Tri-State's primary planning activities center on the preparation of the 10-year Capital Construction Plan for approval by the Tri-State Board. All projects included in Tri-State's 10-year Capital Construction Plan adhere to NERC and WECC Standards and Criteria, FERC Order No. 890 Planning Principles, and coordinated regional planning principles.

Internally, and through WestConnect and CCPG, Tri-State performs annual system assessments to verify compliance with reliability standards, to determine related system improvements, and to demonstrate adherence to the standards and criteria set forth by NERC and WECC. Compliance is certified annually.

During the Local Planning Process, a wide range of factors and interests are considered by Tri-State as part of its reliability assessment, including, but not limited to: (i) the needs of Transmission Customers to integrate loads and resources; (ii) transmission infrastructure upgrades necessary to interconnect new generation resources; (iii) the minimum reliability standard requirements promulgated by NERC and WECC; (iv) bulk electric system considerations above and beyond the NERC and WECC minimum reliability standard requirements; (v) transmission system operational flexibility, which supports economic dispatch of interconnected generation resources; and (vi) various regional and sub-regional transmission projects planned by other utilities and stakeholders.

This comprehensive internal, regional, and sub-regional planning process ensures that Tri-State's local reliability needs are carefully coordinated with all stakeholders.

C. Economic Transmission Planning Study Process

Tri-State shall facilitate priority Local Economic Planning Studies for the Tri-State transmission system, pursuant to the procedures described below. Regional Economic Planning Studies shall be performed by WestConnect, pursuant to Part III of this Attachment.

1. <u>Requesting Economic Planning Studies</u>

   Any Tri-State Transmission Customer or other stakeholder, including sponsors of transmission solutions, generation solutions and solutions utilizing demand

response resources ("Requester"), may submit a study request for an economic planning study directly to Tri-State or WestConnect. Requests submitted to WestConnect will be processed pursuant to Part III of this Attachment.

For requests submitted to Tri-State, the Requester must submit its study request(s) no later than September 1 each year for the study request(s) to be reviewed by Tri-State and discussed with stakeholders at the next open meeting of that year. All such economic planning study requests must be submitted via email to Tri-State (transmissionplanning@tristategt.org).

Economic planning study requests that are developed by Tri-State by September 1 of any year also shall be discussed with stakeholders at the next open meeting of that year. Tri-State shall coordinate the timing of its economic planning study cycle with the WestConnect processes.

2. Process for Handling Economic Transmission Planning Study Requests Received by Tri-State

   a. Review of Economic Transmission Study Requests

      All economic planning study requests received by September 1 shall be reviewed by Tri-State prior to the next open planning meeting. Tri-State shall seek stakeholder input on those requests at the next open planning meeting. At the meeting, Tri-State shall state which requests it has determined are local. Based on stakeholder input, Tri-State shall then choose whether the local study requests should be considered a local priority request and facilitated by Tri-State. If Tri-State has determined that the study request is regional or interregional, Tri-State shall transfer the request to WestConnect.

   b. Criteria Used to Determine Whether an Economic Planning Study Request is a Local Economic Planning Study Request

      Based in part on the number and type of economic planning study requests received, Tri-State shall consider the following criteria to determine if the study request is for a local economic planning study or a regional economic planning study:

      i. Whether the study request affects the interconnected transmission system or only Tri-State's transmission system.
      ii. Whether the potential remedies are confined to and only resolvable within Tri-State's local transmission system.

c. Criteria Used to Determine Whether a Local Economic Planning Study Request is a Priority Request

Tri-State shall consider the following criteria to determine whether a Local Economic Planning Study request is a priority request:

i. Which portion(s) of the Tri-State local transmission system shall be under consideration in the study.

ii. Whether the request raises fundamental design issues of interest to multiple parties.

iii. Whether the request raises policy issues of national, regional, or state interest, e.g., with respect to access to renewable power, and location of both conventional and renewable resources.

iv. Whether the objectives of the study can be met by other existing or planned studies.

v. Whether the study shall provide information of broad value to Transmission Customers, regulators, transmission providers and other interested Stakeholders.

vi. Whether similar requests for studies or scenarios can be represented generically if the projects are generally electrically equivalent.

vii. Whether requests can be aggregated into energy or load aggregation zones with generic transmission expansion between them.

viii. Whether the study request requires the use of production cost simulation or whether it can be better addressed through technical studies, i.e., power flow and stability analysis.

d. Priority Local Economic Planning Study Requests

If Tri-State determines that a Local Economic Planning Study request is a priority local request, Tri-State shall facilitate the study and coordinate assumptions and results with its Transmission Customers, stakeholders, and interconnected transmission providers. Tri-State shall have no obligation to facilitate more than three priority Local Economic Planning Studies per calendar year. Tri-State reserves the right to reasonably limit the scope of the priority Local Economic Planning Studies, based on the cohesiveness of the study request as a single study, likely public merit addressing

congestion and/or integration of new resources and loads on an aggregated basis, and study cost. If Tri-State receives more than three requests for Local Economic Planning studies that are determined to be priority local requests, stakeholders and Tri-State shall prioritize the requests to determine which three Tri-State shall facilitate. Tri-State may facilitate one or more additional studies (beyond three) at its sole discretion. If Tri-State elects not to perform such additional studies, Tri-State may assist the Requester in having a third party perform the Local Economic Planning Study at the Requester's expense. Tri-State shall assist the Requester (or such third party) , at the Requestor's expense, in ensuring that the study is coordinated as necessary through local, regional, or interregional planning groups.

4. Low Priority Economic Study Requests

   If Tri-State determines, after review through an open stakeholder process, that a requested Local Economic Planning Study is not a priority study, the Requester may request Tri-State's assistance in having a third party perform the Local Economic Planning Study analysis at the Requester's expense. Tri-State shall have no obligation to fund any low priority Local Economic Planning Study. Tri-State shall assist the Requester, at the Requestor's expense, in ensuring that the study is coordinated as necessary through local or regional planning groups.

5. Clustering Priority Local Economic Planning Studies

   Priority Local Economic Planning Studies may be studied in clusters. Tri-State may decide to study any number of Local Economic Planning Studies together, either on its own initiative, upon the request of a Requester, or to comply with state regulatory requirements, if applicable. Tri-State shall combine such studies as it deems appropriate. Tri-State shall use the following processes to determine whether to cluster priority Local Economic Planning Studies:

   a. Tri-State-Proposed Clusters

      In the event that Tri-State proposes to cluster certain priority Local Economic Planning Studies on any reasonable grounds, including, without limitation, upon its determination that the proposed cluster studies are sufficiently similar, from an electrical perspective, to be feasibly and meaningfully studied as a group, it shall provide notice to each Requester whose study it proposes to include in the cluster study. Each Requester

shall be provided the opportunity to opt out of the cluster within ten (10) calendar days of written notice from Tri-State.

b. Requester-Proposed Clusters

If a Requester wishes to propose a Local Economic Planning cluster study, prior to submitting the Local Economic Planning Study cluster request to Tri-State, the Requester must contact all of the other Requesters whose requests it proposes to cluster and obtain their written consent that they are willing to have their request clustered with other identified requests. All such written consent(s) must be provided to Tri-State before Tri-State shall commence a Local Economic Planning cluster study. Tri-State shall reasonably determine whether the Local Economic Planning Study requests that the Requester proposes to cluster and for which the other affected Requesters have provided consent, are sufficiently similar, from an electrical perspective, to be feasibly and meaningfully studied together. Tri-State reserves the right to reject a Requester-proposed cluster on any reasonable grounds, including, without limitation, upon Tri-State's determination that the proposed cluster cannot be feasibly studied as a group, is not likely to provide a result significantly different than separate studies, or if the proposed clustering impairs administration or timely processing of the Local Economic Planning Study process. Tri-State shall make the determination whether to reject a proposed cluster, and provide notice of any decision to reject, within twenty (20) calendar days of receipt of all of the written consents of the Requesters that propose to be clustered.

6. Cost Responsibility for Economic Planning Studies

a. Priority Local Economic Planning Studies

Tri-State shall facilitate, at Tri-State's cost, up to three priority Local Economic Planning Studies per calendar year. Each of the clustered priority Local Economic Planning Studies shall be deemed to be a single study. Tri-State shall have no obligation to facilitate more than three priority Local Economic Planning Studies per calendar year. For Local Economic Planning Studies not selected, Tri-State may assist the Requester in having a third party perform the Local Economic Planning Study at the Requester's expense.

b. Priority Regional Economic Planning Studies

Priority Regional Economic Planning Studies will be performed by WestConnect.

c. Other Local Economic Planning Study Requests

To the extent Requesters of Local Economic Planning Studies not selected to be performed at Tri-State's cost pursuant to this section wish to have those studies performed, such Local Economic Planning Study requests shall be performed at the Requester's expense. Tri-State may assist the Requester in finding a third party to perform the studies.

7. Exchange of Data Unique to Local Economic Planning Studies

a. Data Used for Local Economic Planning Studies

Tri-State obtains all data used for its local economic planning studies from the WestConnect data base.

b. Request for Base Case Data

Any Requester's request for detailed base case data must be submitted to WECC in accordance with the WECC procedures.

c. Posting of Requests for Local Economic Planning Studies

All requests made to Tri-State for economic planning studies and responses to such requests shall be posted on the Tri-State OASIS and the WestConnect website, subject to confidentiality requirements.

8. Tri-State Point of Contact for Study Requests

Stakeholder questions regarding modeling, criteria, assumptions, and data underlying economic planning studies should be submitted via email to Tri-State (transmissionplanning@tristategt.org).

D. Public Policy Requirement Transmission Planning Study Process

1. Procedures for Identifying Transmission Needs Driven by Public Policy Requirements

Stakeholders may participate in identifying local transmission needs driven by Public Policy Requirements by participating in any one of Tri-State's outreach efforts for stakeholder participation as described in II.A.6 above.

In order to identify transmission needs driven by Public Policy Requirements, Tri-State will consider several factors, including but not limited to:

i. Whether the Public Policy Requirement is driving a local transmission need that can be reasonably identified in the current planning cycle;

ii. The feasibility of addressing the local transmission need driven by the Public Policy Requirement in the current planning cycle;

iii. The basis supporting the local transmission need driven by the Public Policy Requirement; and

iv. Whether a Public Policy Requirement has been identified for which a local transmission need has not yet materialized, or for which there may exist a local transmission need but the development of a solution to that need is premature.

No single factor shall necessarily be determinative in selecting among the potential transmission needs driven by Public Policy Requirements.

2. Procedures for Evaluating Solutions to Identified Transmission Needs Driven by Public Policy Requirements

Stakeholders may provide comments on proposed solutions or may submit other proposed solutions to local transmission needs.

The procedures for evaluating potential solutions to the identified local transmission needs driven by Public Policy Requirements are the same as those procedures used to evaluate any other project proposed in the local planning process.

3. Posting of Public Policy Needs

Tri-State will maintain on its OASIS:

i. A list of all local transmission needs identified that are driven by Public Policy Requirements and that are included in the studies for the current local planning cycle; and

ii. An explanation of why other suggested transmission needs driven by Public Policy Requirements were not evaluated.

III. Regional Transmission Planning Process

This Section of Attachment K to the Tri-State OATT implements the requirements for regional planning set forth in Federal Energy Regulatory Commission Order Nos. 890 and 1000. Tri-State engages in regional planning and coordination within the WestConnect regional process (Regional Planning Process), which also includes Tri-State's participation in interregional planning in the United States portion of the Western Interconnection through its participation in WestConnect.

The purpose of the Regional Planning Process is to produce a regional transmission plan (the Regional Plan) and provide a process for evaluating projects submitted for cost allocation in accordance with the provisions of this Attachment L and those business practices adopted by WestConnect in the WestConnect Regional Planning Process Business Practice Manual, as may be amended from time to time, available on the WestConnect website (Business Practice Manual).

A. Overview

The WestConnect Planning Region is defined by the Transmission Owners and Transmission Provider members (referred to generally as Transmission Owners) participating in the Regional Planning Process and for whom WestConnect is conducting regional planning. The service areas of the Transmission Owners consist of all or portions of nine states: Arizona, California, Colorado, Nebraska, New Mexico, Nevada, South Dakota, Texas and Wyoming. Non-public utilities are invited to participate in the Regional Planning Process.

The WestConnect Order No. 1000 regional transmission planning management committee (the Planning Management Committee or PMC) will be responsible for administering the Regional Planning Process. In order to align its regional process with the western interregional coordination process, WestConnect began its biennial process in 2016. WestConnect conducted an abbreviated planning process in 2015.

In conjunction with creating the new PMC, the WestConnect members, in consultation with interested stakeholders, have established a separate project agreement (the Planning Participation Agreement) to permit interested stakeholders to participate in the Regional Planning Process. Although the Regional Planning Process is open to the public, stakeholders interested in having a voting right in decisions related to the Regional Planning Process will be required to execute the Planning Participation Agreement and any necessary confidentiality agreements. The PMC will implement the stakeholder-developed Regional Planning Process, which will result in a

Regional Plan for the ten-year transmission planning horizon.

Tri-State is a party to the WestConnect STP Project Agreement. The committees formed under the WestConnect STP Project Agreement and the WestConnect Steering Committee have no authority over the PMC and the PMC's decision making in implementing the Regional Planning Process.

1. WestConnect Planning Participation Agreement

Each WestConnect member will be a signatory to the Planning Participation Agreement, which formalizes the members' relationships and establishes obligations, including Transmission Owner coordination of regional transmission planning among the WestConnect participants and the local transmission planning processes, and producing a Regional Plan.

2. Members

WestConnect has two types of members: (i) Transmission Owners that enroll in the WestConnect Planning Region in order to comply with Order No. 1000 planning and cost allocation requirements, as well as Transmission Owners that elect to participate in the
WestConnect Regional Planning Process without enrolling for Order No. 1000 cost allocation purposes, and (ii) stakeholders who wish to have voting input into the methodologies, studies, and decisions made in the execution of those requirements.

a. Joining the WestConnect Planning Region

A Transmission Owner that wishes to enroll or participate in the WestConnect Planning Region may do so by executing the Planning Participation Agreement and paying its share of costs as provided for in the Planning Participation Agreement.

A stakeholder that wishes to have voting input may join the WestConnect Planning Region by executing the Planning Participation Agreement, paying annual dues, and complying with applicable provisions as outlined in such agreement. For further information regarding membership dues, please see WestConnect's Planning Participation Agreement, located at www.westconnect.com and on file with FERC.

b. Exiting the WestConnect Planning Region

Should a Transmission Owner member wish to exit the WestConnect Planning

Region, it must submit notice in accordance with the Planning Participation Agreement and pay its share of any WestConnect expenditures approved prior to providing its formal notice of withdrawal from the WestConnect Planning Region.

Should a stakeholder wish to exit the WestConnect Planning Region, it may do so by providing notice in accordance with the Planning Participation Agreement. Withdrawing stakeholders will forfeit any monies or dues paid to the PMC and agree to remit to the PMC any outstanding monies owed to WestConnect prior to their withdrawal being considered official.

c. List of Enrolled Entities

Transmission Owners enrolled in the WestConnect Planning Region for purposes of Order No. 1000:

- Arizona Public Service Company
- Black Hills Colorado Electric Utility Company, LP
- Black Hills Power, Inc.
- Cheyenne Light, Fuel, & Power Company
- El Paso Electric Company
- NV Energy, Inc. Operating Companies
- Public Service Company of Colorado
- Public Service Company of New Mexico
- Tri-State Generation and Transmission Association, Inc.
- Tucson Electric Power Company
- UNS Electric, Inc.

3. WestConnect Objectives and Procedures for Regional Transmission Planning

The Regional Planning Process will produce a Regional Plan that complies with existing Order No. 890 principles:

a. Coordination

b. Openness

c. Transparency

d. Information exchange

e. Comparability

f. Dispute resolution

Tri-State, along with the other Planning Participation Agreement participants, shall work through the Regional Planning Process to integrate its transmission plan with the other WestConnect participant transmission plans into a single ten year Regional Plan for the WestConnect footprint by:

a. Actively coordinating development of the Regional Plan, including incorporating information, as appropriate, from all stakeholders;

b. Coordinating, developing and updating common base cases to be used for all study efforts within the Regional Planning Process and ensuring that each plan adheres to the methodology and format developed for the Regional Plan;

c. Providing funding for the Regional Planning Process and all planning management functions pursuant to the Planning Participation Agreement;

d. Maintaining a regional planning section at www.westconnect.com where all WestConnect planning information, including meeting notices, meeting minutes, reports, presentations, and other pertinent information is posted;

e. Posting detailed notices of all regional and local planning meeting agendas on the WestConnect website; and

f. Establishing a cost allocation process for regional transmission projects selected in the Regional Planning Process for cost allocation.

B. Roles in the Regional Planning Process

1. PMC Role

The PMC is responsible for bringing transmission planning information together and sharing updates on active projects. The PMC provides an open forum where any stakeholder interested in the planning of the regional transmission system in the WestConnect footprint can participate and obtain information regarding base cases, plans, and projects and provide input or express its needs as they relate to the transmission system. On a biennial basis and in coordination with its members, Transmission Owners, and other interested stakeholders, the PMC will develop the Regional Plan. The PMC, after considering the data and comments supplied by customers and other stakeholders, is to develop a regional transmission plan that treats similarly-situated customers (*e.g.*, network, retail network, and native load) comparably in transmission system planning.

The PMC is charged with development and approval of the Regional Plan. The

PMC is structured to be comprised of representatives from each stakeholder sector. The PMC will be empowered to create and dissolve subcommittees as necessary to facilitate fulfillment of its responsibilities in developing the Regional Plan.

2. Stakeholder Participation and Assistance

Stakeholders may participate in the Regional Planning Process by any one or more of the following ways: (a) joining one of five WestConnect regional transmission planning membership sectors described below; (b) by attending publicly-posted WestConnect regional transmission planning stakeholder meetings; and/or (c) by submitting project proposals for consideration and evaluation in the Regional Planning Process.

Attendance at meetings is open to all interested stakeholders. These meetings will include discussion of models, study criteria and assumptions, and progress updates. Formal participation, including voting as allowed by the process, can be achieved through payment of applicable fees and annual dues in accordance with the Planning Participation Agreement. Transmission Owners with a Load Serving Obligation will not be responsible for annual dues because Transmission Owners with a Load Serving Obligation will be the default source of monies to support WestConnect activities beyond dues paid by other organizations.

WestConnect Planning Region members will assist stakeholders interested in becoming involved in the Regional Planning Process by directing them to appropriate contact persons and websites. (*See* at www.westconnect.com). All stakeholders are encouraged to bring their plans for future generators, loads or transmission services to the WestConnect planning meetings. Each transmission planning cycle will contain a period during which project ideas are accepted for potential inclusion in that cycle's Regional Plan.

3. Forum for Evaluation

The WestConnect Regional Planning Process also provides a forum for transmission project sponsors to introduce their specific projects to interested stakeholders and potential partners and allows for joint study of these projects by interested parties, coordination with other projects, and project participation, including ownership from other interested parties. This may include evaluation of transmission alternatives or non-transmission alternatives in coordination with the Regional Planning Process.

4. Stakeholder Meetings

WestConnect will hold open stakeholder meetings on at least a semi-annual basis, or as needed and noticed by the PMC with 30 days advance notice to update stakeholders about its progress in developing the Regional Plan and to solicit input regarding material matters of process related to the Regional Plan. Notice for such meetings will be posted on the WestConnect website and via email to the Regional Planning Process email distribution list.

The meeting agendas for all WestConnect planning meetings will be sufficiently detailed, posted on the WestConnect website, and circulated in advance of the meetings in order to allow stakeholders the ability to choose their meeting attendance most efficiently.

5. WestConnect Planning Process Governance

a. Membership Sectors

The Regional Planning Process will be governed by the PMC, which will be tasked with executing the Regional Planning Process and will have authority for approving the Regional Plan. For those entities desiring to be a part of the management of the Regional Planning Process, one of five PMC membership sectors is available:

- Transmission Owners with Load Serving Obligations
- Transmission Customers
- Independent Transmission Developers and Owners
- State Regulatory Commissions
- Key Interest Groups

Only Transmission Owners that have load serving obligations individually or through their members may join the Transmission Owners with Load Serving Obligations membership sector. The Transmission Owners with Load Serving Obligations sector will be comprised of (a) those Transmission Owners that enroll in the WestConnect Planning Region for purposes of Order No. 1000; and (b) those Transmission Owners that elect to participate in the WestConnect Regional Planning Process as Coordinating Transmission Owners.

Except for Public Utilities that are required to comply with Order No. 1000, any entity may join any membership sector for which it qualifies, but may only participate in one membership sector at a time. If a non-public utility is qualified to join the Transmission Owners with Load Serving Obligations sector as well as

one or more other sectors, and the non-public utility elects to join a sector other than the Transmission Owners with Load Serving Obligations sector, the PMC will not perform the function of regional transmission planning for that entity. Additionally, if a member of the Transmission Owner with Load Serving Obligations sector owns transmission facilities located in another planning region, the PMC will not perform the function of regional planning for such facilities located in another planning region.

b. Planning Management Committee

The PMC will be empowered to create and dissolve subcommittees as necessary to ensure timely fulfillment of its responsibilities; to assess fees for membership status on the PMC; and to assess fees for projects submitted for evaluation as part of the Regional Planning Process. The PMC is to manage the Regional Planning Process, including approval of the Regional Plan that includes application of regional cost allocation methodologies.

The PMC is to coordinate and have the decision making authority over whether to accept recommendations from the Planning Subcommittee (PS) and Cost Allocation Subcommittee (CAS). The PMC, among other things, is to develop and approve the Regional Plan based on recommendations from the PS and CAS; and develop and approve a scope of work, work plan, and periodic reporting for WestConnect planning functions, including holding a minimum of two stakeholder informational meetings per year. The PMC is to appoint the chair of the PS and CAS. The chair for each subcommittee must be a representative of the Transmission Owners with Load Serving Obligations member sector.

The PS responsibilities include, but are not limited to, reviewing and making recommendations to the PMC for development of study plans, establishing base cases, evaluating potential solutions to regional transmission needs, producing and recommending the Regional Plan for PMC approval, and coordinating with the CAS. The PS is to provide public notice of committee meetings and provide opportunities for stakeholders to provide comments on the process and proposed plan.

The CAS responsibilities include, but are not limited to, performing and/or overseeing the performance of the cost allocation methodology. The CAS also is to review and make recommendations to the PMC for modifying definitions of benefits and cost allocation methodology as necessary to meet WestConnect planning principles on identification of beneficiaries and cost allocation. The CAS is to review and recommend projects to the PMC for purposes of cost allocation identified in the Regional Planning Process. The CAS is to provide public notice of committee meetings and provide opportunities for stakeholders to provide comments on the process and proposed cost allocation.

All actions of the PMC (including approval of the Regional Plan) will be made possible by satisfying either of the following requirements:

- 75% of the members voting of at least three (3) sectors approving a motion, where one of the three sectors approving is the Transmission Owners with Load Serving Obligation sector; or
- 75% of the members voting of the four member sectors other than the Transmission Owners with Load Serving Obligation sector approving a motion and two-thirds (2/3) of the members voting of the Transmission Owners with Load Serving Obligation sector approving a motion.

Each entity within a membership sector is entitled to one vote on items presented for decision.

Any closed executive sessions of the PMC will be to address matters outside of the development of the Regional Planning Process, including matters involving contracts, personnel, financial matters, or legal matters such as, but not limited to, litigation (whether active or threatened).

C. Submission of Data by Customers, Transmission Developers and Transmission Owners

When stakeholder feedback on modeling assumptions is requested, the data submittal period for such feedback will be established by the PMC. In all cases, requests for submittal of data from WestConnect members and stakeholders will be followed by a data submittal window lasting no less than thirty (30) days from the date of such requests. In addition, consistent with the Regional Planning Process, any interested stakeholder may submit project ideas for consideration in the Regional Plan without a need for that stakeholder to qualify for a project submittal for purposes of cost allocation. Specific project submittals are treated differently than generalized project ideas. For any project submittal seeking study by the PMC in the Regional Planning Process to address a regional need identified by the PMC (without regard to whether the project seeks cost allocation), a project submittal deposit will be collected and made subject to later true-up based upon the actual cost of the study(ies) performed. Project submittals are to be accepted through the fifth (5th) quarter of the planning cycle (or first (1st) quarter of the second (2nd) year), and are addressed in Section III.C.5 of this Attachment L. A timeline detailing the timing and notice for submission of information and input can be found in Exhibit 1 of this Attachment L.

1. Transmission Customers

Transmission customers shall generally submit their load forecast and other relevant data through the WestConnect member's (*e.g.*, Tri-State's) local transmission planning process. However, from time to time, there may be a need for transmission customers participating in the Regional Planning Process to submit data directly to WestConnect. This data may include, but is not limited to load forecasts, generation resource plans, demand side management resources, proposed transmission upgrade recommendations, and feedback regarding certain assumptions in the planning process.

No less than thirty (30) days' notice will be given for customers to submit any required data and data submissions will generally be able to be made via email or by posting information to a designated website.

2. Independent Transmission Developers and Owners

Transmission Developers are entities with project ideas they wish to submit into the Regional Planning Process. These may include project submittals that the developer wishes to be considered to address an identified regional need (whether or not the project is eligible for regional cost allocation).

Each regional transmission planning cycle will include a submission period for project ideas as described in Section III.C.5 below. Notice of the submission period will be posted on the WestConnect website and will also be made via email to WestConnect stakeholders. The submission period will last for no less than thirty (30) days and during this time, any entity that wishes to submit a transmission project for consideration in the Regional Planning Process to address an identified regional need may do so.

Projects proposed by Independent Transmission Developers and Owners are subject to the same Reliability Standards as projects submitted by Transmission Owners with Load Serving Obligations. The project developer shall register with NERC and WECC in accordance with the applicable registration rules in the NERC Rules of Procedure. In addition, project developers shall observe and comply with regional requirements as established by the applicable regional reliability organizations, and all local, state, regional, and federal requirements.

3. Merchant Transmission Developers

Merchant Transmission Developers are entities pursuing completion of projects that do not wish to have their projects considered for regional cost allocation.

Nonetheless, coordination between merchant projects and the Regional Planning Process is necessary to effect a coordinated Regional Plan that considers all system needs.

Each regional transmission planning cycle will include a submission period for project submittals to address an identified regional need, as described in Section III.C.5 below. Notice of the submission period will be posted on the WestConnect website and will also be made via email to WestConnect stakeholders. In addition, it is necessary for merchant transmission developers to provide adequate information and data to allow the PMC to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region. The submission period will last for no less than thirty (30) days and during this time sponsors of merchant transmission projects that are believed to impact the WestConnect transmission system will be asked to provide certain project information.

Projects proposed by Merchant Transmission Developers are subject to the same Reliability Standards as projects submitted by Transmission Owners with Load Serving Obligations. The project developer is responsible for properly registering with NERC and WECC in accordance with the applicable registration rules in the NERC Rules of Procedure. In addition, project developers shall observe and comply with regional requirements as established by the applicable regional reliability organization and all local, state, regional, and federal requirements.

4. <u>Transmission Owners with Load Serving Obligations</u>

Transmission Owners that are members of the WestConnect Planning Region are responsible for providing all necessary system information to the Regional Planning Process.

At the beginning of each regional transmission planning cycle, Transmission Owners that are participating in the Regional Planning Process shall be responsible for verifying the accuracy of any data (including, but not limited to system topology and project proposal information) they have previously submitted. Transmission Owners shall also be required to submit all relevant data for any new projects being proposed for inclusion in the Regional Plan to address an identified regional need in accordance with Section III.C.5 below. Transmission Owners shall also be responsible for submitting any project plans developed through their local transmission planning processes for inclusion in the Regional Plan models.

5. <u>Transmission Project Submittals</u>

All submittals of transmission projects to address an identified regional need,

without regard to whether or not the project seeks regional cost allocation, are to contain the information set forth below, together with the identified deposit for study costs, and be submitted timely within the posted submittal period in order for the project submittal to be eligible for evaluation in the Regional Planning Process. A single project submittal may not seek multiple study requests. To the extent a project proponent seeks to have its project studied under a variety of alternative project assumptions, the individual alternatives must be submitted as individual project submittals. To be eligible to propose a project for selection in the Regional Plan, a project proponent must also be an active member in good standing within one of the five PMC membership sectors described above in Section III.B.5.a:

- Submitting entity contact information
- Explanation of how the project is a more efficient or cost-effective solution to regional transmission needs*
- A detailed project description including, but not limited to, the following:
    - Scope
    - Points of interconnection to existing (or planned) system
    - Operating Voltage and Alternating Current or Direct Current status
    - Circuit configuration (Single, Double, Double-Circuit capable, etc.)
    - Impedance information
    - Approximate circuit mileage
- Description of any special facilities (series capacitors, phase shifting transformers, etc.) required for the project
- Diagram showing geographical location and preferred route; general description of permitting challenges
- Estimated Project Cost and description of basis for that cost*
- Any independent study work of or relevant to the project
- Any WECC study work of or relevant to the project
- Status within the WECC path rating process
- The project in-service date
- Change files to add the project to a standard system power flow model
- Description of plan for post-construction maintenance and operation of the proposed line

- A $25,000 deposit to support the cost of relevant study work, subject to true-up (up or down) based upon the actual cost of the study(ies).* The true-up will include interest on the difference between the deposit and the actual cost, with such interest calculated in accordance with section 35.19a(a)(2) of FERC's regulations. A description of the costs to which the deposit was applied, how the costs were calculated, and an accounting of the costs will be provided to each project sponsor within 30 calendar days of the completion of the study. Dispute resolution is addressed pursuant to Section V.
- Comparison Risk Score from WECC Environmental Data Task Force, if available
- Impacts to other regions. The applicant must provide transmission system impacts studies showing system reliability impacts to neighboring transmission systems or another transmission planning region. The information should identify all costs associated with any required upgrades to mitigate adverse impacts on other transmission systems.*

If impact studies and costs are not available at the time of submittal, the project proponent may request that impact studies be performed, at the project proponent's expense, as part of the analysis to determine whether the project is the more efficient or cost-effective solution. Requests for transmission system impact studies are approved through the PMC depending on whether the project proponent provides funding for the analysis. The PMC will provide, subject to appropriate confidentiality and CEII restrictions, the information in the possession of the PMC that an applicant needs to perform the transmission system impact study and to identify the costs associated with any upgrades required to mitigate adverse impacts.

* Merchant transmission developers are exempt from these requirements.

There is to be an open submission period for project proposals to address identified regional needs. Notice of the submission period will be posted on the WestConnect website and will also be made via email to WestConnect stakeholders. The submission period will last for no less than thirty (30) days and will end by the fifth (5th) quarter of the WestConnect planning cycle (or first (1st) quarter of the second (2nd) year of the planning cycle). Proposals submitted outside that window will not be considered. The PMC will have the authority to determine the completeness of a project submittal. Project submittals deemed incomplete will be granted a reasonable opportunity to cure any deficiencies identified in writing by the PMC.

Any stakeholder wishing to present a project submittal to address an identified regional need shall be required to submit the data listed above for the project to be considered in the Regional Planning Process. Should the submitting stakeholder believe certain information is not necessary, it shall identify the information it believes is not necessary and shall provide a justification for its conclusion that the information is not necessary. The PMC retains the sole authority for determining completeness of the information submittal. After the completion of the project submittal period, the PMC will post a document on the WestConnect website detailing why any projects were rejected as incomplete. Upon posting of the document, any project submittal rejected as incomplete will be given a reasonable opportunity to cure the reason(s) it was rejected to the satisfaction of the PMC in its sole discretion.

6. Submission of Non-Transmission Alternative Projects

Any stakeholder may submit projects proposing non-transmission alternatives to address an identified regional need for evaluation under the Regional Planning Process. The submission period will last for no less than thirty (30) days. The submission window will end by the fifth (5th) quarter of the WestConnect planning cycle (or first (1st) quarter of the second (2nd) year of the planning cycle). The following criteria must be satisfied in order for a non-transmission alternative project submittal to be evaluated under the Regional Planning Process:

- Basic description of the project (fuel, size, location, point of contact)
- Operational benefits
- Load offset, if applicable
- Description of the issue sought to be resolved by the generating facility or non-transmission alternative, including reference to any results of prior technical studies
- Network model of the project flow study
- Short-circuit data
- Protection data
- Other technical data that might be needed for resources
- Project construction and operating costs
- Additional miscellaneous data (e.g., change files if available)

As with entities submitting a transmission project under Section III.C.5, those who submit under Section III.C.6 a non-transmission alternative under the

Regional Planning Process must adhere to and provide the same or equivalent information (and deposit for study costs) as transmission alternatives, as described in Section III.C.5, above. Should the submitting stakeholder believe certain information is not necessary, it shall identify the information it believes is not necessary and shall provide a justification for its conclusion that the information is not necessary. Although non-transmission alternative projects will be considered in the Regional Planning Process, they are not eligible for regional cost allocation.

7. The WestConnect Regional Planning Cycle

The WestConnect regional transmission planning cycle is biennial. The WestConnect PMC will develop and publish a Regional Plan every other year.

D. Transmission Developer Qualification Criteria

1. In General

A transmission developer that seeks to be eligible to use the regional cost allocation methodology for a transmission project selected in the Regional Plan for purposes of cost allocation must identify its technical and financial capabilities to develop, construct, own, and operate a proposed transmission project. To be clear, satisfaction of the criteria set forth below does not confer upon the transmission developer any right to:

(i) construct, own, and/or operate a transmission project,
(ii) collect the costs associated with the construction, ownership and/or operation of a transmission project,
(iii) provide transmission services on the transmission facilities constructed, owned and/or operated.

The applicable governing governmental authorities are the only entities empowered to confer any such rights to a transmission developer. The PMC is not a governmental authority.

2. Information Submittal

A transmission developer seeking eligibility for potential designation as the entity eligible to use the regional cost allocation for a transmission project selected in the Regional Plan for purposes of cost allocation must submit to the PMC the following information during the first quarter of the WestConnect planning cycle, except that during the first WestConnect planning cycle the PMC shall have the discretion to extend the period for the submission of this information:

a. Overview

A brief history and overview of the applicant demonstrating that the applicant has the capabilities to finance, own, construct, operate and maintain a regional transmission project consistent with Good Utility Practice within the state(s) within the WestConnect Planning Region. The applicant should identify all transmission projects it has constructed, owned, operated and/or maintained, and the states in which such projects are located.

b. Business Practices

A description of the applicant's experience in processes, procedures, and any historical performance related to engineering, constructing, operating and maintaining electric transmission facilities, and managing teams performing such activities. A discussion of the types of resources, including relevant capability and experience (in-house labor, contractors, other transmission providers, etc.) contemplated for the licensing, design, engineering, material and equipment procurement, siting and routing, Right-of-Way (ROW) and land acquisition, construction and project management related to the construction of transmission projects. The applicant should provide information related to any current or previous experience financing, owning, constructing, operating and maintaining and scheduling access to regional transmission facilities.

c. Compliance History

The applicant should provide an explanation of any violation(s) of NERC and/or Regional Entity Reliability Standards and/or other regulatory requirements pertaining to the development, construction, ownership, operation, and/or maintenance of electric transmission facilities by the applicant or any parent, owner, affiliate, or member of the applicant that is an Alternate Qualifying Entity under Section III.D.2.l. Notwithstanding the foregoing, if at the time the applicant submits the information required by this Section III.D.2, the applicant has not developed, constructed, owned, operated or maintained electric transmission facilities, the applicant shall instead submit such information for any electric distribution or generating facilities it develops, constructs owns, operates and/or maintains, as applicable, to demonstrate its compliance history.

d. Participation in the Regional Planning Process

A discussion of the applicant's participation within the Regional Planning Process or any other planning forums for the identification, analysis, and communication of transmission projects.

e. Project Execution

A discussion of the capability and experience that would enable the applicant to comply with all on-going scheduling, operating, and maintenance activities associated with project development and execution.

f. Right-of-Way Acquisition Ability

The applicant's preexisting procedures and historical practices for siting, permitting, landowner relations, and routing transmission projects including, acquiring ROW and land, and managing ROW and land acquisition for transmission facilities. Any process or procedures that address siting or routing transmission facilities through environmentally sensitive areas and mitigation thereof. If the entity does not have such preexisting procedures, it shall provide a detailed description of its plan for acquiring ROW and land and managing ROW and land acquisition.

g. Financial Health

The applicant must demonstrate creditworthiness and adequate capital resources to finance transmission projects. The applicant shall either have an investment grade credit rating from both S&P and Moody's or provide corporate financial statements for the most recent five years for which they are available. Entities that do not have a credit rating, or entities less than five years old, shall provide corporate financial statements for each year that is available. Alternatively, the applicant may provide a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to the PMC.

The following ratios must be provided with any explanations regarding the ratios:

- Funds from operations-to-interest coverage.
- Funds from operation-to-total debt.
- Total debt-to-total capital.

The applicant must indicate the levels of the above ratios the company will maintain during and following construction of the transmission element.

The PMC may request additional information or clarification as necessary.

h. Safety Program

The applicant must demonstrate that it has an adequate internal safety program, contractor safety program, safety performance record and program execution.

i. Transmission Operations

The applicant must: demonstrate that it has the ability to undertake control center operations capabilities, including reservations, scheduling, and outage coordination; demonstrate that it has the ability to obtain required path ratings; provide evidence of its NERC compliance process and compliance history, as applicable; demonstrate any existing required NERC certifications or the ability to obtain any applicable NERC certifications; establish required Total Transfer Capability; provide evidence of storm/outage response and restoration plans; provide evidence of its record of past reliability performance, as applicable; and provide a statement of which entity will be operating completed transmission facilities and will be responsible for staffing, equipment, and crew training. A potential transmission developer will not be required to have an operations entity under contract at the time it seeks to be eligible to use the regional cost allocation method for a transmission project selected in the Regional Plan for purposes of cost allocation.

j. Transmission Maintenance

The applicant must demonstrate that it has, or has plans to develop, an adequate transmission maintenance program, including staffing and crew training, transmission facility and equipment maintenance, record of past maintenance performance, NERC compliance process and any past history of NERC compliance or plans to develop a NERC compliance program, and provide a statement of which entity will be performing maintenance on completed transmission facilities. A potential transmission developer will not be required to have a maintenance entity under contract at the time it seeks to be eligible to use the regional cost allocation method for a transmission project selected in the Regional Plan for purposes of cost allocation.

k. Regulatory Compliance

The applicant must demonstrate the ability, or plans to develop the ability, to comply with Good Utility Practice, WECC criteria and regional Reliability Standards, NERC Reliability Standards, construction standards, industry standards, and environmental standards.

l. Affiliation Agreements

A transmission developer can demonstrate that it meets these criteria either on its own or by relying on an entity or entities with whom it has a corporate affiliation or other third parties with relevant experience (Alternate Qualifying Entity(ies)). In lieu of a contractual or affiliate relationship with one or more Alternate Qualifying Entity(ies) and to the extent a transmission developer intends to rely upon third parties for meeting those criteria, the transmission developer must provide in attestation form, an identification of its preferred third-party contractor(s) and indicate when it plans to enter into a definitive agreement with its third-party contractor(s). If the transmission developer seeks to satisfy the criteria in whole or in part by relying on one or more Alternate Qualifying Entity(ies), the transmission developer must submit: (1) materials demonstrating to the PMC's satisfaction that the Alternate Qualifying Entity(ies) meet(s) the criteria for which the transmission developer is relying upon the alternate qualifying entity(ies) to satisfy; and (2) a commitment to provide in any project cost allocation application an executed agreement that contractually obligates the Alternate Qualifying Entity(ies) to perform the function(s) for which the transmission developer is relying upon the Alternate Qualifying Entity(ies) to satisfy.

m. WestConnect Membership

A transmission developer must be a member of either the WestConnect Transmission Owners with Load Serving Obligations or Independent Transmission Developers and Owners sector, or must agree to join the WestConnect Transmission Owners with Load Serving Obligations or Independent Transmission Developers and Owners sector and agreed to sign the Planning Participation Agreement if the transmission developer seeks to be an entity eligible to use the regional cost allocation method for a transmission project selected in the Regional Plan for purposes of cost allocation.

n. Other

Any other relevant project development experience that the transmission developer believes may demonstrate its expertise in the above areas.

3. Identification of Transmission Developers Satisfying the Criteria

a. Notification to Transmission Developer

No later than September 30 each year, the PMC is to notify each transmission

developer whether it has satisfied the stated criteria. A transmission developer failing to satisfy one or more of the qualification criteria is to be informed of the failure(s) and accorded an additional opportunity to cure any deficiency(ies) within thirty (30) calendar days of notice from the PMC by providing any additional information.

The PMC is to inform the transmission developer whether the additional information satisfies the qualification criteria within forty-five (45) calendar days of receipt of the additional information.

The PMC is to identify the transmission developers that have satisfied the qualification criteria (the "Eligible Transmission Developers") by posting on the WestConnect website, on or before December 31 of each year.

b. <u>Annual Recertification Process and Reporting Requirements</u>

By June 30 of each year, each Eligible Transmission Developer must submit to WestConnect a notarized letter signed by an authorized officer of the Eligible Transmission Developer certifying that the Eligible Transmission Developer continues to meet the current qualification criteria.

The Eligible Transmission Developer shall submit to the PMC an annual certification fee equal to the amount of the WestConnect annual membership fee. If the Eligible Transmission Developer is a member of WestConnect and is current in payment of its annual membership fee, then no certification fee will be required.

If at any time there is a change to the information provided in its application, an Eligible Transmission Developer shall be required to inform the PMC chair within thirty (30) calendar days of such change so that the PMC may determine whether the Eligible Transmission Developer continues to satisfy the qualification criteria. Upon notification of any such change, the PMC shall have the option to: (1) determine that the change does not affect the status of the transmission developer as an Eligible Transmission Developer; (2) suspend the transmission developer's eligibility status until any deficiency in the transmission developer's qualifications is cured; (3) allow the transmission developer to maintain its eligibility status for a limited time period, as specified by the PMC, while the transmission developer cures the deficiency; or (4) terminate the transmission developer's eligibility status.

c. <u>Termination of Eligibility Status</u>

The PMC may terminate an Eligible Transmission Developer's status if the Eligible Transmission Developer: (1) fails to submit its annual certification letter; (2) fails to pay the applicable WestConnect membership fees; (3) experiences a change in its qualifications and the PMC determines that it may no longer qualify as an Eligible Transmission Developer; (4) informs the PMC that it no longer desires to be an Eligible Transmission Developer; (5) fails to notify the PMC of a change to the information provided in its application within thirty (30) days of such change; or (6) fails to execute the Planning Participation Agreement as agreed to in the qualification criteria within a reasonable time defined by the PMC, after seeking to be an entity eligible to use the regional cost allocation method for a transmission project selected in the Regional Plan for purposes of cost allocation.

E. Overview of Regional Planning Methodology and Evaluation Process

The Regional Planning Process is intended to identify regional needs and more efficient or cost-effective solutions to satisfy those needs. Consistent with Order No. 890, qualified projects timely submitted through the Regional Planning Process will be evaluated and selected from competing solutions and resources such that all types of resources, as described below, are considered on a comparable basis. The same criteria and evaluation process will be applied to competing solutions and/or projects, regardless of type or class of stakeholder proposing them. Where a regional transmission need is identified, the PMC is to perform studies that seek to meet that need through regional projects, even in the absence of project proposals advanced by stakeholders or projects identified through the WECC process. When the PMC performs a study to meet an identified regional need in circumstances where no stakeholder has submitted a project proposal to meet that regional need, the PMC is to pursue such studies in a not unduly discriminatory fashion. The study methods employed for PMC-initiated studies will be the same types of study methods employed for stakeholder-initiated studies (see, e.g., Section III.F addressing the use of NERC Transmission Planning (TPL) Reliability Standards for regional reliability projects, Section III.G addressing the use of production cost modeling for regional economic projects, and Section III.H addressing the identification of Public Policy Requirements for regional public policy-driven projects).

The solution alternatives will be evaluated against one another on the basis of the following criteria to select the preferred solution or combination of solutions: (1) ability to fulfill the identified need practically; (2) ability to meet applicable reliability criteria or NERC Transmission Planning Standards issues; (3) technical, operational and financial feasibility; (4) operational benefits/constraints or issues; (5) cost-effectiveness over the time frame of the study or the life of the facilities, as appropriate (including adjustments, as necessary, for operational

benefits/constraints or issues, including dependability); (6) where applicable, consistency with Public Policy Requirements or regulatory requirements, including cost recovery through regulated rates; and (7) a project must be determined by the PMC to be a more efficient or cost-effective solution to one or more regional transmission needs to be eligible for regional cost allocation, as more particularly described below.

The Regional Planning Process provides for an assessment of regional solutions falling in one or more of the following categories:

- Regional reliability solutions
- Regional economic solutions
- Regional transmission needs driven by Public Policy Requirements
- Non-transmission alternatives

Tri-State encourages all interested stakeholders to consult the Business Practice Manual for additional details regarding the planning process, timing, and implementation mechanics.

All WestConnect Transmission Owners with Load Serving Obligation shall be responsible for submitting their local transmission plans for inclusion in the Regional Plan in accordance with the timeline stated in the Business Practice Manual. Those individual plans will be included in the Regional Plan base case system models.

F. WestConnect Reliability Planning Process

Once the base case is established and verified, the PMC is to perform a regional reliability assessment in which the base case system models will then be checked for adherence to the relevant NERC or WECC Transmission Planning Reliability Standards, through appropriate studies, including, but not limited to, steady-state power flow, voltage, stability, short circuit, and transient studies as outlined in the Business Practice Manual. If a reliability violation is identified in this power flow process, the violation will be referred back to the appropriate Transmission Owner.

The PMC will identify projects to resolve any regional violations that impact more than one Transmission Owner of relevant NERC or WECC Transmission Planning Reliability Standards or WECC criteria. In addition, an opportunity will be afforded to any interested party to propose regional reliability projects that are more efficient or cost-effective than other proposed solutions. The PMC will then

identify the more efficient or cost-effective regional transmission project that meets the identified regional transmission need, taking into account factors such as how long the project would take to complete and the timing of the need. Because local Transmission Owners are ultimately responsible for compliance with NERC Reliability Standards and for meeting local needs the local transmission plans will not be modified, however, the PMC may identify more efficient or cost-effective regional transmission projects. As seen in Exhibit 1 of this Attachment L, the PMC will perform the regional reliability assessment and, if necessary, identify a regional need for transmission projects to resolve any violations that impact more than one Transmission Owner in the fourth quarter of the planning cycle.

G. WestConnect Economic Planning Process

As part of the Regional Planning Process, the PMC is to analyze whether there are projects that have the potential to reduce the total delivered cost of energy by alleviating congestion or providing other economic benefits to the WestConnect Planning Region through production cost modeling. This analysis also utilizes WECC Board-approved recommendations to further investigate congestion within the WestConnect Planning Region for congestion relief or economic benefits that has subsequently been validated by WestConnect. Additional projects may also be proposed by WestConnect stakeholders or developed through the stakeholder process for evaluation of economic benefits. Under the Regional Planning Process, the PMC will identify more efficient or cost-effective regional transmission projects, but will not modify local transmission plans.

The WestConnect economic planning process will analyze benefits via detailed production cost simulations. The models employed in the production cost simulations will appropriately consider the impact of transmission projects on production cost and system congestion. The WestConnect economic planning process will also consider the value of decreased reserve sharing requirements in its development of a plan that is more efficient or cost-effective. As seen in Exhibit 1 of this Attachment L, the PMC will develop the production cost modeling analysis in the second (2nd) and third (3rd) quarters of the planning cycle and identify economic transmission projects in the sixth (6th) quarter and parts of the fifth (5th) and seventh (7th) quarters of the planning cycle.

H. WestConnect Public Policy Planning Process

1. <u>Procedures for Identifying Transmission Needs Driven by Public Policy Requirements</u>

It is anticipated that any regional transmission need that is driven by Public Policy

Requirements will be addressed initially within the local planning cycles of the individual Transmission Owners in the WestConnect Planning Region through the consideration of local transmission needs driven by a Public Policy Requirement, since a Public Policy Requirement is a requirement that is imposed upon individual Transmission Owners (as opposed to a requirement that is imposed on a geographic region). For those Public Policy Requirements that affect more than one Transmission Owner in the WestConnect Planning Region, a solution identified at the local level to satisfy the local needs of the affected Transmission Owner(s), may also satisfy a regional transmission need identified by the PMC for the WestConnect Planning Region.

WestConnect Transmission Owner members that are planning consistent with Order No. 890 will continue to conduct local transmission planning processes (Section II.E of this Attachment L), which provide a forum for discussions on local transmission needs driven by Public Policy Requirements. These local processes provide the basis for the individual Transmission Owners' local transmission plans, which are then incorporated into the regional base case at the start of the Regional Planning Process under Order No. 1000.

The PMC is to provide notice on the WestConnect website of both regional transmission planning meetings convened by the PMC for the WestConnect region, and local transmission planning meetings of the individual Transmission Owners in the WestConnect region.

The PMC will begin the evaluation of regional transmission needs driven by Public Policy Requirements by identifying any Public Policy Requirements that are driving local transmission needs of the Transmission Owners in the WestConnect Planning Region, and including them in the transmission system models (the regional base case) underlying the development of the Regional Plan. Then, the PMC will seek the input of stakeholders in the WestConnect region on those Public Policy Requirements in an effort to engage stakeholders in the process of identifying regional transmission needs driven by Public Policy Requirements. The PMC will communicate with stakeholders through public postings on the WestConnect website of meeting announcements and discussion forums. In addition, the PMC is to establish an email distribution list for those stakeholders who indicate a desire to receive information via electronic list serves.

After allowing for stakeholder input on regional transmission needs driven by Public Policy Requirements and regional solutions to those needs, as part of the Regional Planning Process, the PMC is to identify in the Regional Plan those regional transmission needs driven by Public Policy Requirements that were selected by the PMC for evaluation of regional solutions.

In selecting those regional transmission needs driven by Public Policy Requirements that will be evaluated for regional solutions in the current planning cycle, the PMC is to consider, on a non-discriminatory basis, factors, including but not limited to, the following:

(i) whether the Public Policy Requirement is driving a regional transmission need that can be reasonably identified in the current planning cycle;

(ii) the feasibility of addressing the regional transmission need driven by the Public Policy Requirement in the current planning cycle;

(iii) the factual basis supporting the regional transmission need driven by the Public Policy Requirement; and

(iv) whether a Public Policy Requirement has been identified for which a regional transmission need has not yet materialized, or for which there may exist a regional transmission need but the development of a solution to that need is premature.

No single factor shall necessarily be determinative in selecting among the potential regional transmission needs driven by Public Policy Requirements.

The process by which the PMC is to identify those regional transmission needs for which a regional transmission solution(s) will be evaluated, out of what may be a larger set of regional transmission needs, is to utilize the communication channels it has in place with stakeholders, identified above (open meetings and discussion forums convened by the PMC), through which regional transmission needs driven by Public Policy Requirements are to be part of the open dialogue.

2. <u>Procedures for Identifying Solutions to Regional Transmission Needs Driven by Public Policy Requirements</u>

Stakeholders are to have opportunities to participate in discussions during the Regional Planning Process with respect to the development of solutions to regional transmission needs driven by Public Policy Requirements. Such participation may take the form of attending planning meetings, offering comments for consideration by the PMC on solutions to regional needs driven by Public Policy Requirements, and offering comments on proposals made by other stakeholders or by the PMC. Stakeholders that are members of the WestConnect PMC are performing the function of regional transmission planning and developing regional solutions to identified regional transmission needs driven by Public Policy Requirements through membership on subcommittees of the PMC.

After allowing for stakeholder input on solutions to regional transmission needs driven by Public Policy Requirements, as part of the Regional Planning Process, the PMC is to identify in the Regional Plan those regional transmission solutions driven by Public Policy Requirements that were selected by the PMC and any regional transmission project(s) that more efficiently or cost-effectively meet those needs.

The procedures for identifying and evaluating potential solutions to the identified transmission needs driven by Public Policy Requirements are the same as those procedures used to evaluate any other project proposed in the Regional Planning Process, whether or not submitted for purposes of cost allocation.

The PMC will perform a Public Policy Requirements analysis to help identify if a transmission solution is necessary to meet an enacted public policy. For a transmission need driven by Public Policy Requirements, the PMC will identify if a more efficient or cost-effective regional transmission solution exists based upon several different considerations, including consideration of whether the project is necessary and capable of meeting transmission needs driven by Public Policy Requirements, while also

(i) Efficiently resolving any criteria violations identified by studies pursuant to any relevant NERC Transmission Planning (TPL) Reliability Standards for regional reliability projects or WECC Transmission Planning Reliability Standards or WECC criteria, as applicable, that could impact more than one Transmission Owner as a result of a Public Policy Requirement or,

(ii) Producing economic benefits shown through detailed production cost simulations. The models employed in the production cost simulations will appropriately consider the impact of transmission projects on production cost, system congestion and the value of decreased reserve sharing requirements.

The PMC will develop the public policy analysis in the sixth (6th) quarter and parts of the fifth (5^{th}) and seventh (7^{th}) quarters of the planning cycle.

3. Proposed Public Policy

A public policy that is proposed, but not required (because it is not yet enacted or promulgated by the applicable governmental authority) may be considered through Section III.G (WestConnect Economic Planning Process) of this Attachment L, if time and resources permit.

4. Posting of Public Policy Needs

WestConnect will maintain on its website (i) a list of all transmission needs identified that are driven by Public Policy Requirements and that are included in the studies for the current regional transmission planning cycle; and (ii) an explanation of why other suggested transmission needs driven by Public Policy Requirements will not be evaluated.

I. Consideration of Non-Transmission Alternatives

Non-transmission alternatives submitted in accordance with Section III.C.6 above will be evaluated to determine if they will provide a more efficient or cost-effective solution to an identified regional transmission need. Non-transmission alternatives include, without limitation, technologies that defer or possibly eliminate the need for new and/or upgraded transmission lines, such as distributed generation resources, demand-side management (load management, such as energy efficiency and demand response programs), energy storage facilities and smart grid equipment that can help eliminate or mitigate a grid reliability problem, reduce uneconomic grid congestion, and/or help to meet grid needs driven by Public Policy Requirements. Non-transmission alternatives are not eligible for regional cost allocation.

J. Approval of the WestConnect Regional Plan

The Cost Allocation Subcommittee is to submit, for review and comment, the results of its project benefit/cost analysis and beneficiary determination to the PMC Chair and to the identified beneficiaries of the transmission projects proposed for cost allocation. The PMC shall make available to its Members sufficient information to allow for a reasonable opportunity to comment on the proposed selection. The PMC shall not make a determination on the project benefit/cost analysis and beneficiary determination until it has reviewed all comments. Upon approval of the PMC, the project benefit/cost analysis and beneficiary identifications shall be posted by the PMC on the WestConnect website.

1. CTO Acceptance of Cost Allocation

(i) Each coordinating transmission owner (CTO) beneficiary will indicate whether it accepts the cost allocation for the project, as follows:

1. A CTO Member, in its sole discretion, may elect to accept a cost allocation for each separate transmission facility for which it is identified as a beneficiary, but only if it notifies the Chair of the

PMC in writing of its decision to accept any such cost allocation within sixty (60) calendar days after the benefit/cost analysis is posted by the PMC under this Section III.J; provided, however, that the PMC has the discretion to extend the 60-day period when additional time is necessary for an identified beneficiary to complete its internal review and deliberation process before deciding to accept the cost allocation.

2. A CTO Member giving notice that it elects to accept a cost allocation for a transmission facility may rescind that notice at any time prior to the end of the sixty (60) day period, or such extended period established in this Section III.J.1.
3. A CTO Member that does not accept a cost allocation for a transmission facility will not be subject to cost allocation for that transmission facility.

The information made available under this Section III.J will be electronically masked and made available pursuant to a process that the PMC reasonably determines is necessary to prevent the disclosure of confidential information or CEII contained in the information.

2. <u>Recalculation of Benefits and Costs for Reliability Projects</u>

The Cost Allocation Subcommittee will adjust, as necessary, its project benefit/cost analysis and beneficiary identification for any transmission project that continues to meet the region's criteria for regional cost allocation. For any CTO beneficiary that does not accept cost allocation for a project under this Section III.J, such CTO's transmission need(s) which was included within the identification of the region's transmission needs under Sections III.F through III.H (for which the regional project would have avoided an alternative reliability project in such CTO's local transmission plan) will be removed as a regional transmission need for purposes of justifying a project's approval as a project eligible for inclusion in the Regional Plan for purposes of cost allocation.

3. <u>Recalculation of Benefits and Costs for Public Policy Requirements Projects</u>

The Cost Allocation Subcommittee will adjust, as necessary, its project benefit/cost analysis and beneficiary identification for any transmission project that continues to meet the region's criteria for regional cost allocation. For any CTO beneficiary that does not accept cost allocation for a project under this Section III.J, such CTO's transmission need(s) which was included within the identification of the region's transmission needs under Sections III.F through

III.H (for which the regional project would have avoided an alternative Public Policy Requirements project in such CTO's local transmission plan) will be removed as a regional transmission need for purposes of justifying a project's approval as a project eligible for inclusion in the Regional Plan for purposes of cost allocation. This shall include any such CTO's resource needs necessary to comply with Public Policy Requirements.

4. Recalculation of Benefits and Costs for Economic Projects

The Cost Allocation Subcommittee will adjust, as necessary, its project benefit/cost analysis and beneficiary identification for any transmission project that continues to meet the region's criteria for regional cost allocation. For any CTO beneficiary that does not accept cost allocation for a project under this Section III.J, such CTO's transmission benefits which were included within the identification of the regional project's economic benefits under Sections III.F through III.H will be removed as a regional transmission benefit for purposes of justifying a project's approval as a project eligible for inclusion in the Regional Plan for purposes of cost allocation. This shall include the value of any economic benefits determined through the regional transmission plan to accrue to such CTO.

5. Resultant Increase in Beneficiary Cost Allocation

Any regional transmission project that continues to meet the region's benefit/cost and other criteria for regional cost allocation will remain eligible for selection in the Regional Plan for purposes of cost allocation.

6. Approval of the WestConnect Regional Transmission Plan

Upon completion of the process outlined above, the PMC will vote on whether to accept the proposed plan. The Regional Plan will document why projects were either included or not included in the Regional Plan. In addition, the Regional Plan is to describe the manner in which the applicable regional cost allocation methodology was applied to each project selected in the Regional Plan for purposes of regional cost allocation. Projects that meet system needs are incorporated into the Regional Plan. Participant funded projects and other types of projects may be included in the Regional Plan; however, those projects are not eligible for regional cost allocation.

K. Reevaluation of the WestConnect Regional Plan

The PMC is the governing body responsible for deciding whether to reevaluate the Regional Plan to determine if the conditions, facts and/or circumstances relied

upon in initially selecting a transmission project for inclusion in the Regional Plan for purposes of cost allocation have changed and, as a result, require reevaluation. Reevaluation will begin within the second planning cycle following December 11, 2014, which is the effective date of the Planning Participation Agreement. The Regional Plan and any project selected for cost allocation in the Regional Plan, including any local or single-system transmission projects or planned transmission system upgrades to existing facilities selected for purposes of cost allocation, shall be subject to reevaluation in each subsequent planning cycle according to the criteria below. Upon reevaluation, the Regional Plan and any projects selected for purposes of cost allocation in connection therewith may be subject to modification, including the status as a project selected for cost allocation, with any costs reallocated under Section VI as if it were a new project. Only the PMC has the authority to modify the status of a transmission project selected for cost allocation. Conditions that trigger reevaluation are:

- The underlying project characteristics and/or regional or interregional needs change in the Regional Plan. Examples include, but are not limited to: (a) a project's failure to secure a developer, or a developer's failure to maintain the qualifications necessary to utilize regional cost allocation, or (b) a change (increase or decrease) in the identified beneficiaries of a project (which changes may occur through company acquisitions, dissolutions, or otherwise), (c) a change in the status of a large load that contributes to the need for a project, or (d) projects affected by a change in law or regulation;
- Projects that are delayed and fail to meet their submitted in-service date by more than two (2) years. This includes projects delayed by funding, regulatory approval, contractual administration, legal proceedings (including arbitration), construction delays, or other delays;
- Projects with significant project changes, including, but not limited to kilovolt (kV), megavolt ampere (MVA), or path rating, number of circuits, number of transmission elements, or interconnection locations; and
- Projects with a change in the calculation of benefits or benefit/cost (B/C) ratio that may affect whether the project selected for inclusion in the Regional Plan for purposes of cost allocation is a more efficient or cost-effective regional solution.
  - Example 1: Where an increase in the selected project's costs, including but not limited to, material, labor, environmental mitigation, land acquisition, operations and maintenance, and mitigation for identified transmission system and region, causes the total project costs to increase above the level upon which the project was initially selected for inclusion in the Regional Plan for purposes

of cost allocation, the inclusion of the regional project in the Regional Plan will be reevaluated to determine if the regional project continues to satisfy the region's B/C ratio and can be found to be a more efficient or cost-effective solution under current cost information.

- Example 2: A selected project's benefits may include identification of a reliability benefit in the form of remedying a violation of a Reliability Standard. If the identified beneficiary implements improvements, such as a Remedial Action Scheme, to achieve reliability in compliance with the Reliability Standard at issue, inclusion of the regional project in the regional plan will be reevaluated to determine if the regional project continues to satisfy the region's B/C ratio and can be found to be a more efficient or cost-effective solution under current benefit information.
- Example 3: Where a project's estimated benefits include benefits in the form of avoided costs (e.g., a regional project's ability to avoid a local project), and the project is not avoided, the inclusion of the regional project in the Regional Plan will be reevaluated to determine if the regional project continues to satisfy the region's B/C ratio and can be found to be a more efficient or cost-effective solution under current facts and circumstances.

Projects selected for purposes of cost allocation will continue to be reevaluated until all the following conditions have been met:

- State and federal approval processes completed and approved (including cost recovery approval under Section 205 of the Federal Power Act as applicable);
- All local, state, and federal siting permits have been approved; and
- Major construction contracts have been issued.

When the Regional Plan is reevaluated as a result of any of the conditions triggering reevaluation addressed above, the PMC is to determine if an evaluation of alternative transmission solutions is needed in order to meet an identified regional need. In doing so, the PMC is to use the same processes and procedures it used in the identification of the original transmission solution to the regional need. If an alternative transmission solution is needed, the incumbent Transmission Owner may propose one or more solutions that it would implement within its retail distribution service territory or footprint, and if such proposed solution is a transmission facility, the Transmission Owner may submit the project for possible

selection in the Regional Plan for purposes of cost allocation.

Projects not subject to reevaluation include, but are not limited to, the following:

- Local or single system transmission projects that have been identified in individual Transmission Owner's Transmission Planning (TPL) Reliability Standards compliance assessments to mitigate reliability issues and that have not been proposed for (and selected by the PMC for) regional cost allocation; and
- Planned transmission system upgrades to existing facilities that have not been proposed for (and selected by the PMC for) regional cost allocation.

Projects meeting any of the following criteria as of December 11, 2014 will also not be subject to reevaluation under the Regional Planning Process:

- Projects of Transmission Owners who have signed the Planning Participation Agreement and that have received approval through local or state regulatory authorities or board approval;
- Local or single system transmission projects that have been planned and submitted for inclusion in the Regional Plan or exist in the 10-year corporate capital project budgets; and
- Projects that are undergoing review through the WECC Project Coordination and Rating Review Process as of December 11, 2014.

L. Confidential or Proprietary Information

Although the Regional Planning Process is open to all stakeholders, Stakeholders will be required to comply at all times with certain applicable confidentiality measures necessary to protect confidential information, proprietary information or CEII. From time to time the regional transmission planning studies and/or open stakeholder meetings may include access to base case data that are WECC proprietary data, information classified as CEII, or other similar confidential or proprietary information. In such cases, access to such confidential or proprietary information shall be limited to only those stakeholders that (i) hold membership in or execute a non-disclosure agreement (NDA) with WECC (See www.wecc.biz) or (ii) execute a non-disclosure agreement with the applicable WestConnect Planning Region members, as may be applicable.

Any entity wishing to access confidential information, subject to applicable Standards of Conduct requirements, discussed in the Regional Planning Process must execute an NDA, and submit it to mailto:NDA@westconnect.com.

IV. Coordination at the Western Interconnection Level

A. Tri-State – WestConnect Coordination

Tri-State shall coordinate its plan on a regional basis through WestConnect. WestConnect will coordinate its Regional Plan withWECC.

B. Procedures for Interregional Planning Project Review

1. WECC Coordination of Reliability Planning

a. WECC develops the Western Interconnection-wide databases for transmission planning analysis such as power flow, stability and dynamic voltage stability studies. The WECC-approved base cases are used for study purposes by transmission planners, regional transmission planning groups, and other entities that have signed non-disclosure agreements with WECC.

b. WECC maintains a database for reporting the status of all planned projects throughout the Western Interconnection.

c. WECC provides for coordination of planned projects through its Procedures for Regional Planning project review.

d. WECC's path rating process ensures that a new project will have no adverse effect on existing projects.

2. WECC-WECC Open Stakeholder Meetings

Western Interconnection-wide economic planning studies are conducted by the WECC WECC in an open stakeholder process that holds region-wide stakeholder meetings on a regular basis. The WECC procedures for prioritizing and completing regional economic studies, is posted on the WECC website at www.wecc.biz. Tri-State participates in the region-wide planning processes, as appropriate, to ensure data and assumptions are coordinated.

3. Role of WECC

WECC provides two main functions in relation to the WestConnect Regional Planning Process:

a. Development and Maintenance of the West-Wide Economic Planning Study Database.

(i) WECC uses publicly available data to compile a database that can be used by a number of economic congestion study tools.

(ii) WECC's database is available for use in running economic congestion studies. For an interested stakeholder to utilize WECC's PROMOD planning model, it must comply with WECC confidentiality requirements.

b. Performance of Economic Planning Studies

WECC has hierarchy of subcommittees and work groups which it will update databases, develop and approve a study plan that includes studying transmission customer high priority economic planning study requests as determined by the open WECC stakeholder process, perform the approved studies and document the results in a report.

c. Identification of Congested Paths for WestConnect Economic Review

Through WECC's economic study process, congested paths may be reviewed and identified as being candidates for economic transmission studies. Upon WECC Board approval of a designation for such a path and WestConnect validation, the Regional Planning Process will review the path for potential economic transmission solutions.

V. Dispute Resolution

In the event of a dispute concerning either a procedural or substantive matter within the jurisdiction of FERC, the following dispute resolution processes will apply:

A. WECC

If the dispute is one that is within the scope of the WECC dispute resolution procedures, then such procedures contained in the WECC Business and Governance Guidelines and Policies will apply. (See www.wecc.biz.)

B. Non-WECC Disputes

For disputes not within the scope of the WECC dispute resolution procedures, and

for disputes not between or among the members of the PMC (which disputes will be subject to the dispute resolution provisions set forth in Section V.D), the dispute resolution procedures set forth in Section 12 of the Tri-State OATT will apply, with the added provision that upon agreement of the parties, any dispute that is not resolved by direct negotiation between or among the affected arbitration), and all applicable timelines will be suspended until such time as the mediation process terminates (unless otherwise agreed by the parties). Notwithstanding that the dispute resolution procedures under Section 12 of the Tri-State OATT apply only to Tri-State and its Transmission Customers, Section 12 of the Tri-State OATT will be deemed to be applicable to stakeholders for purposes of this Attachment L, except as otherwise provided herein.

C. Resolution by FERC

Notwithstanding anything to the contrary in this Section V, any affected party may refer either a procedural or substantive matter within the jurisdiction of FERC to FERC for resolution, for example, by filing with FERC a complaint, a request for declaratory order, or a change in rate.

D. Disputes Between PMC Members

For disputes between members of the PMC, the following dispute resolution procedures are to apply:

1. Initiating Dispute Resolution

The disputing PMC member(s) initiates its dispute by providing written notification to the PMC (or a designated sub-committee of the PMC) in accordance with the provisions of the Planning Participation Agreement, in which event the PMC will seek to resolve the dispute through discussion, negotiation and the development of a recommended course of action. The PMC may act to adopt a resolution recommended by its own committee members or sub-committees, or alternatively the disputing parties may act to refer the dispute to arbitration for resolution.

2. Arbitration

A dispute may be referred to arbitration under the governing provisions of the Planning Participation Agreement.

3. Resolution by FERC

The availability of the dispute resolution avenues identified above does not eliminate a disputing PMC member's(s') right under the Federal Power Act to

refer either a procedural or substantive matter within the jurisdiction of FERC to FERC for resolution, for example by filing with FERC a complaint, a request for declaratory order or a change in rate.

VI. Cost Allocation

A. Local Transmission Projects

Local Transmission Projects are projects located within a Transmission Owner's retail distribution service territory or footprint unless such projects are submitted and selected in the Regional Plan for purposes of cost allocation. A Transmission Owner is not precluded from proposing Local Transmission Projects for inclusion in the Regional Plan for purposes of cost allocation in the Regional Planning Process. A Local Transmission Project that is not submitted or not selected for inclusion in the Regional Plan is not eligible for cost allocation in the Regional Plan, and not subject to the provisions governing regional cost allocation set forth below.

For any transmission project where Tri-State is the sole owner or such project is to be built within or for the benefit of the existing Tri-State system such as local, small and/or reliability transmission projects, Tri-State shall proceed with the project pursuant to its rights and obligations as a Transmission Provider for the local area. Any projects necessary to ensure reliability or that provide economic benefits to the Tri-State system and that fall outside the requirements for inclusion in the Regional Plan for purposes of cost allocation are eligible to be considered Local Transmission Projects.

Tri-State may share ownership, and associated costs, of any new transmission project, based upon mutual agreement between the parties. Such a joint ownership arrangement may arise because of existing joint ownership of facilities in the area of the new facilities, overlapping service territories, or other relevant considerations.

1. <u>Open Season Solicitation of Interest</u>

For any transmission project identified in a Tri-State reliability or economic planning study in which Tri-State is the project sponsor, Tri-State may elect to provide an "open season" solicitation of interest to secure additional project participants. Upon a determination by Tri-State to hold an open season solicitation of interest for a transmission project, Tri-State will:

a. Announce and solicit interest in the project through informational meetings, the Tri-State company website at:

https://www.tristategt.org/transmission-planning website, and/or other means of dissemination as appropriate.

b. Hold meetings with interested parties, state public utility commission staffs from potentially affected states, and other affected stakeholders.
c. Post information via the Tri-State company website at: https://www.tristategt.org/transmission-planning.
d. Develop the initial transmission project specifications, the initial cost estimates and potential transmission line routes; guide negotiations and assist interested parties to determine cost responsibility for initial studies; guide the project through the applicable line siting processes; develop final project specifications and costs; obtain commitments from participants for final project cost shares; and secure execution of construction and operating agreements.
e. Whether as a project sponsor or a participant, coordinate as necessary with any other participant or sponsor, as the case may be, to integrate into Tri-State's Ten Year Transmission Plan any other planned project on or interconnected with Tri-State's transmission system.

B. Regional Transmission Projects

For any project determined by the PMC to be eligible for regional cost allocation, project costs will be allocated proportionally to those entities determined by the PMC, as shown in the Regional Plan, to be beneficiaries in the WestConnect Planning Region, as identified in this Attachment L, subject to the processes set forth in Sections III through VI.

The PMC, with input from the CAS, is to determine whether a project is eligible for regional cost allocation, and assesses the project's costs against its benefits in accordance with the following factors:

- Benefits and beneficiaries will be identified before cost allocation methods are applied.
- Cost assignments shall be commensurate with estimated benefits.
- Those that receive no benefits must not be involuntarily assigned costs.
- A benefit-to-cost threshold of not more than 1.25 shall be used, as applicable, so that projects with significant benefits are not excluded.
- Costs must be allocated solely within the WestConnect Planning Region, unless other regions or entities voluntarily assume costs.
- Costs for upgrades on neighboring transmission systems or other planning regions that are (i) required to be mitigated by the WECC Path Rating

process, FERC tariff requirements, or NERC Reliability Standards, or (ii) negotiated among interconnected parties will be included in the total project costs and used in the calculation of B/C ratios.

- Cost allocation method and data shall be transparent and with adequate documentation.
- Different cost allocation methods may be used for different types of projects.

Specifically, the PMC will consider the following projects eligible for cost allocation consideration as further described below based on specified criteria:

- Reliability projects;
- Economic or congestion relief projects; or
- Public policy projects.

Only projects that fall within one or more of these three categories and satisfy the cost-to-benefit analyses and other requirements, as specified herein, are eligible for cost allocation in the WestConnect Planning Region. Tri-State encourages all interested stakeholders to consult the Business Practice Manual for additional details regarding the assessment for eligibility for regional cost allocation. Summary provisions are provided below.

1. Allocation of Costs for Reliability Projects

In order to allocate costs to Transmission Owners for system reliability improvements that are necessary for their systems to meet the NERC TPL standards, the WestConnect cost allocation procedure shall allocate costs for system reliability improvements only when a system improvement is required to comply with the NERC TPL Reliability Standards during the planning horizon.

All components of a Transmission Owner's local transmission plan shall be included in the Regional Plan and shall be considered Local Transmission Projects that are not eligible for regional cost allocation. A system performance analysis shall be performed on the collective plans to ensure the combined plans adhere to all relevant NERC TPL Reliability Standards and stakeholders shall be afforded an opportunity to propose projects that are more efficient or cost-effective than components of multiple Transmission Owner local plans as outlined in Section III.F, above.

Should a reliability issue be identified in the review of the included local transmission

plan, the project necessary to address that reliability issue shall be included in the Regional Plan and the cost shall be shared by the utilities whose load contributed to the need for the project.

Should multiple utilities have separate reliability issues that are addressed more efficiently or cost-effectively by a single regional project, that regional project shall be approved for selection in the Regional Plan and the cost shall be shared by those Transmission Owners in proportion to the cost of alternatives that could be pursued by the individual Transmission Owners to resolve the reliability issue. The ultimate responsibility for maintaining system reliability and compliance with NERC Transmission Planning Standards rests with each Transmission Owner.

The costs for regional reliability projects shall be allocated according to the following equation:

(1 divided by 2) times 3 equals 4

Where:

1 is the cost of local reliability upgrades necessary to avoid construction of the regional reliability project in the relevant Transmission Owner’s retail distribution service territory or footprint

2 is the total cost of local reliability upgrades in the combination of Transmission Owners’ retail distribution service territories or footprints necessary to avoid construction of the regional reliability project

3 is the total cost of the regional reliability project

4 is the total cost allocated to the relevant Transmission Owner’s retail distribution service territory or footprint

The manner in which the PMC applied this methodology to allocate the costs of each regional reliability project shall be described in the Regional Plan.

2. Allocation of Costs for Economic Projects

Cost allocation for economic projects associated with congestion relief that provide for more economic operation of the system will be based on the calculation of economic benefits that each Transmission Owner system will receive. Cost allocation for economic projects shall include scenario analyses to ensure that benefits will actually be received by beneficiaries with relative certainty. Projects for which benefits and beneficiaries are highly uncertain and vary beyond reasonable parameters based on assumptions about future conditions

will not be selected for cost allocation.
In order for a project to be considered economically-justified and receive cost allocation associated with economic projects, the project must have a B/C ratio that is greater than 1.0 under each reasonable scenario evaluated and have an average ratio of at least 1.25 under all reasonable scenarios evaluated. Costs will be allocated on the basis of the average of all scenarios evaluated. The B/C ratio shall be calculated by the PMC. This B/C ratio shall be determined by calculating the aggregate load-weighted benefit-to-cost ratio for each transmission system in the WestConnect Planning Region. The benefits methodology laid out below ensures that the entities that benefit the most from the completion of an economic project are allocated costs commensurate with those project benefits.

The cost of any project that has an aggregate 1.25 B/C ratio or greater will be divided among the Transmission Owners that show a benefit based on the amount of benefits calculated to each respective Transmission Owner. For example, if a $100 million dollar project is shown to have $150 million in economic benefit, the entities for which the economic benefit is incurred will be determined. The cost of the project will then be allocated to those entities, based on the extent of each entity's economic benefits relative to the total project benefits. This will ensure that each entity that is allocated cost has a B/C ratio equal to the total project B/C ratio. For example:

- Project with $150 million in economic benefit and $100 million in cost
    - Company 1 has $90 million in benefits; Company 2 has $60 million in benefits
    - Company 1 allocation: 90/150 (100) = $60 million
    - Company 1 B/C ratio: 90/60 = 1.5
    - Company 2 allocation: 60/150 (100) = $40 million
    - Company 2 B/C ratio: 60/40 = 1.5

Other than through the reevaluation process described in Section III.J of this Attachment L, the benefits and costs used in the evaluation shall only be calculated during the planning period and shall be compared on a net present value basis.

The WestConnect economic planning process shall consider production cost savings and reduction in reserve sharing requirements as economic benefits capable of contributing to the determination that a project is economically justified for cost allocation. Production cost savings are to be determined by the PMC performing a product cost simulation to model the impact of the

transmission project on production costs and congestion. Production cost savings will be calculated as the reduction in production costs between a production cost simulation with the project included compared to a simulation without the project. Reductions in reserve sharing requirements are to be determined by the PMC identifying a transmission project's impact on the reserve requirements of individual transmission systems, and not on the basis of the project's collective impact on a reserve sharing group, as a whole. The production cost models are to appropriately consider the hurdle rates between transmission systems. The following production cost principles may be applied:

- The production cost savings from a project must be present in each year from the project in-service date and extending out at least ten (10) years.
- Cost savings must be expressed in present-value dollars and should consider the impact of various fuel cost forecasts.
- The production cost study must account for contracts and agreements related to the use of the transmission system (this refers to paths in systems that might be contractually limited but not reliability limited).
- The production cost study must account for contracts and agreements related to the access and use of generation (this refers to generators that might only use spot purchases for fuel rather than firm purchases, or generation that has been designated as network resources for some entities and thus cannot be accessed at will by non-owners).

Access by stakeholders to the PMC's application of its regional cost allocation method for a specific economic transmission project is available in several ways: First, stakeholders that are members of the PMC will have firsthand knowledge of the way in which the regional method was applied to a particular project because the PMC is responsible for performing the application of the regional cost allocation method. Second, stakeholders that choose not to become members of the PMC may access such information through the WestConnect regional stakeholder process. See Section III.B of this Attachment L. Third, the manner in which the PMC applied this methodology to allocate the costs of each economic project shall be described in the Regional Plan.

In determining which entities shall be allocated costs for economic projects, WestConnect shall compare the economic value of benefits received by an entity with the cost of the project to ensure that each entity allocated cost receives a benefit/cost ratio equal to the aggregate load-weighted benefit-to-cost ratio. These costs allocated to each company shall be calculated based on the following equation:

(1 divided by 2) times 3 equals 4

Where:

1 is the total projected present value of economic benefits for the relevant Transmission Owner

2 is the total projected present value of economic benefits for the entire project

3 is the total cost of the economic project

4 is the total cost allocated to the relevant Transmission Owner

Any Transmission Owner with benefits less than or equal to one percent of total project benefits shall be excluded from cost allocation. Where a project satisfies the B/C ratio, and is determined to provide benefits less than or equal to one percent of total project benefits to an identified Transmission Owner, such benefits will be re-allocated to all other identified beneficiaries on a pro rata basis, in relation to each entity's share of total project benefits.

3. <u>Allocation of Costs for Public Policy Projects</u>

Any transmission system additions that arise from Public Policy Requirements shall be included in the system models used for the WestConnect transmission system studies. Further, any additional system needs that arise from proposed public policy shall be reported by each entity for its own service territory. Decisions on the inclusion of those needs shall be made during the consideration and approval of the system models. Transmission needs driven by Public Policy Requirements will be included in the evaluation of reliability and economic projects.

Except for projects proposed through a Transmission Owner's local planning process, arising out of a local need for transmission infrastructure to satisfy Public Policy Requirements that are not submitted as projects proposed for cost allocation (which are addressed in Section II of this Attachment L), any projects arising out of a regional need for transmission infrastructure to satisfy the Public Policy Requirements shall be considered public policy projects eligible for evaluation in the Regional Planning Process.

Stakeholders may participate in identifying regional transmission needs driven by Public Policy Requirements. After seeking the input of stakeholders pursuant to the stakeholder participation provisions of Section III, the PMC is to determine

whether to move forward with the identification of a regional solution to a particular regional need driven by Public Policy Requirements. Stakeholders may participate in identifying a regional solution to a regional need driven by Public Policy Requirements pursuant to the stakeholder participation provisions of Section III, or through membership on the PMC itself. After seeking the input of stakeholders, the PMC is to determine whether to select a particular regional solution in the regional transmission plan for purposes of cost allocation. The identification of beneficiaries of these projects shall be the entities that shall access the resources enabled by the project in order to meet their Public Policy Requirements.

If an entity accesses resources that were enabled by a prior public policy project, that entity shall need to either share in its relative share of the costs of that public policy project or acquire sufficient transmission service rights to move the resources to its load with the determination left up to the entity or entities that were originally allocated the cost for the public policy project. The costs for public policy projects shall be allocated according to the following equation:

(1 divided by 2) times 3 equals 4

Where:

1 is the number of megawatts of public policy resources enabled by the public policy project for the entity in question

2 is the total number of megawatts of public policy resources enabled by the public policy project

3 is the total project cost

4 is the cost for the public policy project allocated to the entity in question

The process to interconnect individual generation resources would be provided for under the generator interconnection section each utility's OATT and not under this process.

Requests for transmission service that originate in a member's system and terminate at the border shall be handled through that member's OATT. Regional transmission needs necessary to meet Public Policy Requirements shall be addressed through the Public Policy Requirements section of the Regional Planning Process.

The manner in which WestConnect applied this methodology to each public policy project shall be described in the Regional Transmission Plan.

4. Combination of Benefits

In developing a more efficient or cost-effective plan, it is possible for the plan to jointly consider multiple types of benefits when approving projects for inclusion in the Regional Plan. The determination to consider multiple types of benefits for a particular project shall be made through the WestConnect stakeholder process, in which interested stakeholders are given an opportunity to provide input as set forth in Section III of this Attachment L. In determining whether a project would provide multiple benefits, the PMC is to categorize the benefits as (a) necessary to meet NERC Transmission Planning Reliability Standards (reliability); (b) achieving production cost savings or a reduction in reserve sharing requirements (economic); or (c) necessary to meet transmission needs driven by Public Policy Requirements, as applicable, using the methods set forth in this Attachment L. The PMC will identify all three categories of benefits in its regional cost allocation process. If a project cannot pass the cost allocation threshold for any one of the three benefit categories, alone (reliability, economic or public policy), the sum of benefits from each benefit category may be considered.

- With respect to a reliability-driven regional transmission project, the quantified benefits of the project to each identified beneficiary must be greater, by a margin of 1.25 to 1, than the result of the equation identified in Section VI.B.1 above (where the result is shown as item 4 in the formula).
- With respect to an economic-driven regional transmission project, the quantified benefits of the project to each identified beneficiary must be greater than the project's cost to each beneficiary under each reasonable scenario evaluated, and must yield an average ratio of at least 1.25 to 1 under all reasonable scenarios evaluated, as described in Section VI.B.2 above.
- With respect to a Public Policy Requirements-driven regional transmission project, the quantified benefits of the project to each identified beneficiary must be greater, by a margin of 1.25 to 1, than the result of the equation identified in Section VI.B.3 above (where the result is shown as item 4 in the formula).

If a single regional transmission project is determined to provide benefits in more than one category, but does not meet the cost-benefit threshold for any single category, the PMC may consider the sum of benefits from each benefit category to determine if the regional transmission project provides, in total, benefits per beneficiary that meet or exceed the region's 1.25 to 1 benefit to cost ratio. To illustrate, consider the following example where a regional project developed to provide public policy requirement benefits might also provide for economic benefits to the same beneficiaries:

A regional project submittal has undergone analysis for its quantifiable

benefits and costs and is determined to cost $100 million and produce benefits to identified beneficiaries in two categories: economic benefits of $101 million (on average, under all economic scenarios quantified), and public policy requirement benefits of $70 million. The project is found to fail the cost-benefit threshold for each category, individually, but when the total benefits are combined and the project's total regional benefits per beneficiary are weighed against the project's total costs per beneficiary, the project can be found to meet or surpass the region's 1.25 to 1 benefit to cost ratio per beneficiary:

- The benefits to Beneficiary A of pursuing the regional solution (60% of the regional project's total $171 million in benefits) = $102.6 million. When $102.6 million in project benefits is compared against $60 million in project costs (60% of project costs), it yields a B/C ratio of 1.71 to 1 for Beneficiary A.
- The benefits to Beneficiary B of pursuing the regional solution (40% of the regional project's total $171 million in benefits) = $68.4 million. When $68.4 million in project benefits is compared against $40 million in project costs (40% of project costs), it yields a B/C ratio of 1.71 to 1 for Beneficiary B.

Even though the regional project does not pass the cost allocation threshold in any individual benefit category, the PMC may consider the sum of the project's benefits in all categories.

For those regional projects that satisfy the region's cost allocation threshold, the PMC then will continue its evaluation process by considering whether the regional project meets the region's identified reliability, economic and Public Policy Requirements-driven needs more efficiently or cost-effectively than solutions identified by individual transmission providers in their local transmission planning processes.

The costs for projects that rely upon multiple types of benefits to secure inclusion in the Regional Plan for purposes of cost allocation shall be shared according to the amount of cost that is justified by each type of benefit.

5. Allocation of Ownership and Capacity Rights

An Eligible Transmission Developer that is subject to the Commission's jurisdiction under Section 205 of the Federal Power Act may not recover project costs from identified beneficiaries in the WestConnect Planning Region without securing approval for project cost recovery from FERC through a separate proceeding brought by the Eligible

Transmission Developer under Section 205 of the Federal Power Act. In no event will identified beneficiaries in the WestConnect Planning Region from whom project costs are sought to be recovered under Section 205 be denied either transmission transfer capability or ownership rights proportionate to their allocated costs, as determined by FERC in such proceeding. An Eligible Transmission Developer that is not subject to the Commission's jurisdiction under Section 205 of the Federal Power Act would have to seek cost recovery from identified beneficiaries in the WestConnect Planning Region either: (a) through bilateral agreements that are voluntarily entered into between such Eligible Transmission Developer and the applicable identified beneficiaries; or (b) by obtaining approval from FERC for project cost recovery pursuant to any other applicable section of the Federal Power Act.

If a project beneficiary receives transmission transfer capability on the project in exchange for transmission service payments, such project beneficiary may resell the transfer capability. Alternatively, a project beneficiary could seek to make a direct capital contribution to the project construction cost (in lieu of making transmission service payments) in which case the project beneficiary would instead receive an ownership percentage in proportion to their capital contribution ("Ownership Proposal"). This Ownership Proposal does not create a right of first refusal for transmission beneficiaries.

An ownership alternative will only be pursued if the Eligible Transmission Developer agrees. The Eligible Transmission Developer and the beneficiaries will enter into contract negotiations to address the many details regarding the capital funding mechanics and timing, as well as other details, such as defining (as between the Eligible Transmission Developer, whether a nonincumbent or incumbent transmission developer, and those receiving ownership interests) responsibility for operations and maintenance, administrative tasks, compliance with governing laws and regulations, etc. These negotiations will take place at arm's length, without any one party having undue leverage over the other.

A transmission project beneficiary should not be expected to pay for its benefits from the project twice: once through a capital contribution, and again through transmission service payments. The Ownership Proposal permits an ownership share in a project that is in the same proportion to a beneficiary's allocable costs, which costs will have been allocated roughly commensurate with the benefits to be gained from the project. This will allow the beneficiary to earn a return on its investment. In addition, it allows those beneficiaries that may not necessarily benefit from additional transfer capability on a new transmission project, whether due to lack of contiguity to the new facilities or otherwise, to realize the benefits through an ownership option.

Any transmission project participant that is identified as a beneficiary of the project might be permitted by the Eligible Transmission Developer to contribute capital (in lieu of transmission service payments) and receive a proportionate share of ownership rights

in the transmission project. The Ownership Proposal affords an identified beneficiary who contributes toward the project costs the opportunity to obtain an ownership interest in lieu of an allocated share of the project costs through transmission service payments for transfer capability on the project; it does not, however, confer a right to invest capital in a project. The Ownership Proposal merely identifies that, to the extent it is agreed among the parties that capital may be contributed toward a transmission project's construction, a proportionate share of ownership rights will follow.

Nothing in this Attachment L with respect to Order No. 1000 cost allocation imposes any new service on beneficiaries. Similarly, nothing in this Attachment L with respect to Order No. 1000 cost allocation imposes on an Eligible Transmission Developer an obligation to become a provider of transmission services to identified beneficiaries simply as a result of a project's having been selected in the Regional Plan for purposes of cost allocation; provided, however, if that Eligible Transmission Developer seeks authorization to provide transmission services to beneficiaries or others, and to charge rates or otherwise recover costs from beneficiaries or others associated with any transmission services it were to propose, it must do so by contract and/or under separate proceedings under the Federal Power Act. The purpose of this Section VI.B.5 is to (a) provide an option to a project developer to negotiate ownership rights in the project with identified beneficiaries, if both the developer and the identified beneficiaries mutually desire to do so, (b) specify that, although Order No. 1000 cost allocation does not impose any new service on beneficiaries, identified beneficiaries have the opportunity to discuss with the project developer the potential for entering into transmission service agreements for transmission capacity rights in the project, and (c) ensure that Order No. 1000 cost allocation does not mean that a project developer may recover project costs from identified beneficiaries without providing transmission transfer capability or ownership rights, and without securing approval for project cost recovery by contract and/or under a separate proceeding under the Federal Power Act.

6. Project Development Schedule

The WestConnect PMC will not be responsible for managing the development of any project selected for inclusion in the Regional Plan. However, after having selected a project in the Regional Plan, the PMC will monitor the status of the project's development. If a transmission facility is selected for inclusion in the Regional Plan for purposes of cost allocation, the transmission developer of that transmission facility must submit a development schedule that indicates the required steps, such as the granting of state approvals, necessary to develop and construct the transmission facility such that it meets the regional transmission needs of the WestConnect Planning Region. As part of the ongoing monitoring of the status of the transmission project once it is selected, the Transmission Owners and Providers in the WestConnect Planning Region shall establish the dates by which the required steps to construct must be achieved that are tied to when

construction must begin to timely meet the need that the project is selected to address. If such required steps have not been achieved by those dates, then the Transmission Owners and Providers in the WestConnect Planning Region may remove the transmission project from the selected category and proceed with reevaluating the Regional Plan to seek an alternative solution.

7. Economic Benefits or Congestion Relief

For a transmission project wholly within the Transmission Provider's local transmission system that is undertaken for economic reasons or congestion relief at the request of a Requester, the project costs will be allocated to the Requester. A "Requester" is defined as any Tri-State transmission customer or other stakeholder, including sponsors of transmission solutions, generation solutions and solutions utilizing demand response resources.

8. Tri-State Rate Recovery

Notwithstanding the foregoing provisions, Tri-State shall not assume cost responsibility for any transmission project if the cost of the project is not reasonably expected to be recoverable in Tri-State's wholesale transmission rates.

9. Selection of a Transmission Developer for Sponsored and Unsponsored Projects

For any project (sponsored or unsponsored) determined by the PMC to be eligible for regional cost allocation and selected in the Regional Plan for purposes of cost allocation, the PMC shall select a transmission project developer according to the processes set forth in this section, provided that selection according to those processes does not violate applicable law where the transmission facility is to be built that otherwise prescribes the entity that shall develop and build the project. Any entity that, pursuant to applicable law for the location where the facilities are to be built, shall or chooses to develop and build the project must submit a project development schedule as required by Section VI.B.6 of this Attachment L, within the timeframe directed by the Business Practice Manual, not to exceed the time period for request for proposal responses.

For any project determined by the PMC to be eligible for regional cost allocation and selected in the Regional Plan for purposes of cost allocation, either sponsored by a transmission developer or unsponsored, that is not subject to the foregoing paragraph, the PMC shall upon posting the selected projects, issue a request for information to all Eligible Transmission Developers under Section III.D.3 of this Attachment L soliciting their interest in developing the project(s).

Each transmission developer shall respond to the request for information

indicating its interest in developing the project. The PMC shall post on the WestConnect website the list of all transmission developers who responded with an expression of interest in developing the project(s). The PMC shall provide to each developer indicating interest in developing a project a request for proposals for the identified project(s) with a specified date of return for all proposals. Each transmission developer, or partnership or joint ventures of transmission developers, shall submit information demonstrating its ability to finance, own and construct the project consistent with the guidelines for doing so set forth in the WestConnect Business Practices Manual. The PMC shall assess the submissions according to the following process and criteria:

The evaluation of the request for proposals will be at the direction of the PMC, and will involve representatives of the beneficiaries of the proposed project(s). The evaluation will include, but not be limited to, an assessment of the following evidence and criteria.

- General qualifications of the bidding entity;
- Evidence of financing/financial creditworthiness, including
    - financing plan (sources debt and equity), including construction financing and long-term financing
    - ability to finance restoration/forced outages
    - credit ratings
    - financial statements;
- Safety program and experience;
- Project description, including
    - detailed proposed project description and route
    - design parameters
    - design life of equipment and facilities
    - description of alternative project variations;
- Development of project, including
    - experience with and current capabilities and plan for obtaining state and local licenses, permits, and approvals
    - experience with and current capabilities and plan for obtaining any federal licenses and permits
    - experience with and expertise and plan for obtaining rights of way
    - development schedule
    - development budget;
- Construction, including
    - experience with and current capabilities and plan for project construction
    - third party contractors

  - procurement plan
  - project management (cost and schedule control)
  - construction schedule
  - construction budget (including all construction and period costs;
- Operations, including
  - experience with and current capabilities and plan for project operation
  - experience with and current capabilities and plan for NERC compliance
  - security program and plan
  - storm/outage response plan
  - reliability of facilities already in operation;
- Maintenance capabilities and plans for project maintenance (including staffing, equipment, crew training, and facilities);
- Project cost to beneficiaries, including
  - total project cost (development, construction, financing, and other non- O&M costs)
  - operation and maintenance costs, including evaluation of electrical losses
  - revenue requirement, including proposed cost of equity, FERC incentives, proposed cost of debt and total revenue requirement calculation
  - present value cost of project to beneficiaries.

The PMC shall notify the developers of its determination as to which developer(s) it selected to develop the project(s) responsive to the request for proposal. The selected developer(s) must submit a project development schedule as required by Section VI.B.6 of this Attachment L.

If the PMC determines that a sponsored or unsponsored project fails to secure a developer through the process outlined in this section, the PMC shall remove the project from the Regional Plan.

After the PMC makes a determination, it will post a document on the WestConnect website within 60 days explaining the PMC's determination in selecting a particular transmission developer for a specific transmission project. The information will explain (1) the reasons why a particular transmission developer was selected or not selected, and, if applicable, (2) the reasons why a transmission project failed to secure a transmission developer.

10. <u>No Obligation to Construct</u>

The Regional Planning Process is intended to determine and recommend more efficient or cost-effective transmission solutions for the WestConnect Planning Region. After the Regional Plan is approved, due to the uncertainty in the planning process and the need to address cost recovery issues, the Regional Planning Process shall not obligate any entity to construct, nor obligate any entity to commit to construct, any facilities, including any transmission facilities, regardless of whether such facilities are included in any plan. Nothing in this Attachment L or the Planning Participation Agreement or any cost allocation under the Business Practice Manual or the Planning Participation Agreement will (1) determine any transmission service to be received by, or any transmission usage by, any entity, (2) obligate any entity to purchase or pay for, or obligate any entity to commit to purchase or pay for, any transmission service or usage, or (3) entitle any entity to recover for any transmission service or usage or to recover from any entity any cost of any transmission facilities, regardless of whether such transmission facilities are included in any plan. Without limiting the generality of the foregoing, nothing in this Attachment L, the Business Practice Manual or the Planning Participation Agreement with respect to an Order No. 1000 cost allocation shall preclude WestConnect or any other entity from carrying out any of its statutory authorities or complying with any of its statutory obligations.

11. <u>Binding Order No. 1000 Cost Allocation Methods</u>

Order No. 1000 cost allocation methods as set forth in Section VI of this Attachment L are binding on identified beneficiaries enrolled in the WestConnect Planning Region, without prejudice to the following rights and obligations: (1) the right of a CTO, at its sole discretion, to decide whether to accept regional cost allocation in accordance with Section III.J; (2) the right and obligation of the PMC to reevaluate a transmission facility previously selected for inclusion in the regional plan for purposes of Order No. 1000 cost allocation under Section III.K of this Attachment L; (3) the right and obligation of an Eligible Transmission Developer to make a filing under Section 205 or other applicable provision of the Federal Power Act in order to seek approval from the Commission to recover the costs of any transmission facility selected for inclusion in the regional plan for purposes of Order No. 1000 cost allocation; (4) the right and obligation of any interested person to intervene and be heard before the Commission in any Section 205 or other applicable provision proceeding initiated by an Eligible Transmission Developer, including the right of any identified beneficiaries of the transmission facility to support or protest the filing and to present evidence on whether the proposed cost recovery is or is not just and reasonable; and (5) the right and obligation of the Commission to act under Section 205 or other applicable provisions of the Federal Power Act to approve or deny any cost recovery sought by an Eligible Transmission Developer for a transmission facility selected in the regional plan for purposes of Order No. 1000 cost allocation.

12. Impacts of a Regional Project on Neighboring Planning Regions

The PMC is to study the impact(s) of a regional transmission project on neighboring planning regions, including the resulting need, if any, for mitigation measures in such neighboring planning regions. If the PMC finds that a regional transmission project in the WestConnect Planning Region causes impacts on a neighboring planning region that requires mitigation (a) by the WECC Path Rating Process, (b) under FERC OATT requirements, (c) under NERC Reliability Standards requirements, and/or (d) under any negotiated arrangement between the interconnected entities, the PMC is to include the costs of any such mitigation measures into the regional transmission project's total project costs for purposes of determining the project's eligibility for regional cost allocation under the procedures identified in Section VI.B of this Attachment L, including application of the region's benefits-to-costs analysis.

The WestConnect Planning Region will not be responsible for compensating a neighboring planning region, Transmission Provider, Transmission Owner, Balancing Area Authority, or any other entity, for the costs of any required mitigation measures, or other consequences, on their systems associated with a regional transmission project in the WestConnect Planning Region, whether identified by the PMC or the neighboring system(s). The PMC does not direct the construction of transmission facilities, does not operate transmission facilities or provide transmission services, and does not charge or collect revenues for the performance of any transmission or other services. Therefore, in agreeing to study the impacts of a regional transmission facility on neighboring planning regions, the PMC is not agreeing to bear the costs of any mitigation measures it identifies. However, the PMC will request of any developer of a regional transmission project selected in the Regional Plan for purposes of cost allocation that the developer design and build its project to mitigate the project's identified impacts on neighboring planning regions. If the project is identified as impacting a neighboring planning region that accords less favorable mitigation treatment to the WestConnect Planning Region than the WestConnect Planning Region accords to it, the PMC will request that the project developer reciprocate by using the lesser of (i) the neighboring region's mitigation treatment applicable to the mitigation of impacts of its own regional projects on the WestConnect Planning Region, or (ii) the PMC's mitigation treatment set forth above in sub-sections (a) through (d).

13. Exclusions

The cost for transmission projects undertaken in connection with requests for generation interconnection or transmission service on the Tri-State transmission system, which are governed by existing cost allocation methods within the OATT,

shall continue to be so governed and shall not be subject to the principles of this Section VI.

As provided in Section 13.5 (Transmission Customer Obligations for Facility Additions or Redispatch Costs), Section 27 (Compensation for New Facilities and Redispatch Costs) and Section 31.2 (New Network Loads Connected with the Transmission Provider) of the OATT, and the Transmission Customer's individual service agreement (if applicable), the Transmission Customer or Requester shall be responsible for the installed cost of all new load serving interconnections or upgrades to existing load serving interconnections.

VII. Interregional Planning

This Part VII of Attachment L sets forth common provisions, which are to be adopted by or for each Planning Region and which facilitate the implementation of Order No. 1000 interregional provisions. WestConnect is to conduct the activities and processes set forth in this Part VII of this part of Attachment L in accordance with the provisions of this Part VII of this part of Attachment L and the other provisions of this Attachment L. Nothing in this part will preclude any transmission owner or transmission provider from taking any action it deems necessary or appropriate with respect to any transmission facilities it needs to comply with any local, state, or federal requirements. Any Interregional Cost Allocation regarding any ITP (as defined herein) is solely for the purpose of developing information to be used in the regional planning process of each Relevant Planning Region, including the regional cost allocation process and methodologies of each such Relevant Planning Region. References in this Part VII to any transmission planning processes, including cost allocations, are references to transmission planning processes pursuant to Order No. 1000.

A. Definitions

The following capitalized terms where used in this Part VII of Attachment L, are defined as follows:

Annual Interregional Coordination Meeting: shall have the meaning set forth in Section VII.C below.

Annual Interregional Information: shall have the meaning set forth in Section VII.B below.

Interregional Cost Allocation: means the assignment of ITP costs between or among Planning Regions as described in Section VII.E.2 below.

Interregional Transmission Project ("ITP"): means a proposed new transmission project that would directly interconnect electrically to existing or planned transmission facilities in two or more Planning Regions and that is submitted into the regional transmission planning processes of all such Planning Regions in accordance with Section VII.D.1.

Order 1000 Common Interregional Coordination and Cost Allocation Tariff Language: means this Part VII, which relates to Order No. 1000 interregional provisions.

Planning Region: means each of the following Order No. 1000 transmission planning regions insofar as they are within the Western Interconnection: California Independent System Operator Corporation, ColumbiaGrid, Northern Tier Transmission Group, and WestConnect.

Relevant Planning Regions: means, with respect to an ITP, the Planning Regions that would directly interconnect electrically with such ITP, unless and until such time as a Relevant Planning Region determines that such ITP will not meet any of its regional transmission needs in accordance with Section VII.D.2, at which time it shall no longer be considered a Relevant Planning Region.

B. Annual Interregional Information Exchange

Annually, prior to the Annual Interregional Coordination Meeting, WestConnect is to make available by posting on its website or otherwise provide to each of the other Planning Regions the following information, to the extent such information is available in its regional transmission planning process, relating to regional transmission needs in WestConnect's transmission planning region and potential solutions thereto:

(i) study plan or underlying information that would typically be included in a study plan, such as:

(a) identification of base cases;

(b) planning study assumptions; and

(c) study methodologies;

(ii) initial study reports (or system assessments); and

(iii) regional transmission plan

(collectively referred to as "Annual Interregional Information").

WestConnect is to post its Annual Interregional Information on its website according to its regional transmission planning process. Each other Planning Region may use in its regional transmission planning process WestConnect's Annual Interregional Information. WestConnect may use in its regional transmission planning process Annual Interregional Information provided by other Planning Regions.

WestConnect is not required to make available or otherwise provide to any other Planning Region (i) any information not developed by WestConnect in the ordinary course of its regional transmission planning process, (ii) any Annual Interregional Information to be provided by any other Planning Region with respect to such other Planning Region, or (iii) any information if WestConnect reasonably determines that making such information available or otherwise providing such information would constitute a violation of the Commission's Standards of Conduct or any other legal requirement. Annual Interregional Information made available or otherwise provided by WestConnect shall be subject to applicable confidentiality and CEII restrictions and other applicable laws, under WestConnect's regional transmission planning process. Any Annual Interregional Information made available or otherwise provided by WestConnect shall be "AS IS" and any reliance by the receiving Planning Region on such Annual Interregional Information is at its own risk, without warranty and without any liability of WestConnect, including any liability for (a) any errors or omissions in such Annual Interregional Information, or (b) any delay or failure to provide such Annual Interregional Information.

C. Annual Interregional Coordination Meeting

WestConnect is to participate in an Annual Interregional Coordination Meeting with the other Planning Regions. WestConnect is to host the Annual Interregional Coordination Meeting in turn with the other Planning Regions, and is to seek to convene such meeting in February, but not later than March 31st. The Annual Interregional Coordination Meeting is to be open to stakeholders. WestConnect is to provide notice of the meeting to its stakeholders in accordance with its regional transmission planning process.

At the Annual Interregional Coordination Meeting, topics discussed may include the following:

(i) each Planning Region's most recent Annual Interregional Information (to the extent it is not confidential or protected by CEII or other legal restrictions);

(ii) identification and preliminary discussion of interregional solutions, including conceptual solutions, that may meet regional transmission needs in each of two or more Planning Regions more cost effectively or efficiently; and

(iii) updates of the status of ITPs being evaluated or previously included in WestConnect's regional transmission plan.

D. ITP Joint Evaluation Process

1. Submission Requirements

A proponent of an ITP may seek to have its ITP jointly evaluated by the Relevant Planning Regions pursuant to Section VII.D.2 by submitting the ITP into the regional transmission planning process of each Relevant Planning Region in accordance with such Relevant Planning Region's regional transmission planning process and no later than March 31st of any even-numbered calendar year. Such proponent of an ITP seeking to connect to a transmission facility owned by multiple transmission owners in more than one Planning Region must submit the ITP to each such Planning Region in accordance with such Planning Region's regional transmission planning process. In addition to satisfying each Relevant Planning Region's information requirements, the proponent of an ITP must include with its submittal to each Relevant Planning Region a list of all Planning Regions to which the ITP is being submitted.

2. Joint Evaluation of an ITP

For each ITP that meets the requirements of Section VII.D.1, WestConnect (if it is a Relevant Planning Region) is to participate in a joint evaluation by the Relevant Planning Regions that is to commence in the calendar year of the ITP's submittal in accordance with Section VII.D.1 or the immediately following calendar year. With respect to any such ITP, WestConnect (if it is a Relevant Planning Region) is to confer with the other Relevant Planning Region(s) regarding the following:

(i) ITP data and projected ITP costs; and

(ii) the study assumptions and methodologies it is to use in evaluating the ITP pursuant to its regional transmission planning process.

For each ITP that meets the requirements of Section VII.D.1, WestConnect (if it is a Relevant Planning Region):

(a) is to seek to resolve any differences it has with the other Relevant Planning

Regions relating to the ITP or to information specific to other Relevant Planning Regions insofar as such differences may affect WestConnect's evaluation of the ITP;

(b) is to provide stakeholders an opportunity to participate in WestConnect's activities under this Section VII.D.2 in accordance with its regional transmission planning process;

(c) is to notify the other Relevant Planning Regions if WestConnect determines that the ITP will not meet any of its regional transmission needs; thereafter WestConnect has no obligation under this Section VII.D.2 to participate in the joint evaluation of the ITP; and

(d) is to determine under its regional transmission planning process if such ITP is a more cost effective or efficient solution to one or more of WestConnect's regional transmission needs.

E. Interregional Cost Allocation Process

1. Submission Requirements

For any ITP that has been properly submitted in each Relevant Planning Region's regional transmission planning process in accordance with Section VII.D.1, a proponent of such ITP may also request Interregional Cost Allocation by requesting such cost allocation from WestConnect and each other Relevant Planning Region in accordance with its regional transmission planning process. The proponent of an ITP must include with its submittal to each Relevant Planning Region a list of all Planning Regions in which Interregional Cost Allocation is being requested.

2. Interregional Cost Allocation Process

For each ITP that meets the requirements of Section VII.E.1, WestConnect (if it is a Relevant Planning Region) is to confer with or notify, as appropriate, any other Relevant Planning Region(s) regarding the following:

(i) assumptions and inputs to be used by each Relevant Planning Region for purposes of determining benefits in accordance with its regional cost allocation methodology, as applied to ITPs;

(ii) WestConnect's regional benefits stated in dollars resulting from the ITP, if any; and

(iii) assignment of projected costs of the ITP (subject to potential reassignment of projected costs pursuant to Section VII.F.2 below) to

each Relevant Planning Region using the methodology described in this Section VII.E.2.

For each ITP that meets the requirements of Section VII.E.1, WestConnect (if it is a Relevant Planning Region):

(a) is to seek to resolve with the other Relevant Planning Regions any differences relating to ITP data or to information specific to other Relevant Planning Regions insofar as such differences may affect WestConnect's analysis;

(b) is to provide stakeholders an opportunity to participate in WestConnect's activities under this Section VII.E.2 in accordance with its regional transmission planning process;

(c) is to determine its regional benefits, stated in dollars, resulting from an ITP; in making such determination of its regional benefits in WestConnect, WestConnect is to use its regional cost allocation methodology, as applied to ITPs;

(d) is to calculate its assigned *pro rata* share of the projected costs of the ITP, stated in a specific dollar amount, equal to its share of the total benefits identified by the Relevant Planning Regions multiplied by the projected costs of the ITP;

(e) is to share with the other Relevant Planning Regions information regarding what its regional cost allocation would be if it were to select the ITP in its regional transmission plan for purposes of Interregional Cost Allocation; WestConnect may use such information to identify its total share of the projected costs of the ITP to be assigned to WestConnect in order to determine whether the ITP is a more cost effective or efficient solution to a transmission need in WestConnect;

(f) is to determine whether to select the ITP in its regional transmission plan for purposes of Interregional Cost Allocation, based on its regional transmission planning process; and

(g) is to endeavor to perform its Interregional Cost Allocation activities pursuant to this Section VII.E.2 in the same general time frame as its joint evaluation activities pursuant to Section VII.D.2.

F. Application of Regional Cost Allocation Methodology to Selected ITP

1. Selection by All Relevant Planning Regions

If WestConnect (if it is a Relevant Planning Region) and all of the other Relevant Planning Regions select an ITP in their respective regional transmission plans for purposes of Interregional Cost Allocation, WestConnect is to apply its regional cost allocation methodology to the projected costs of the ITP assigned to it under Section VII.E.2(d) or VII.E.2(e) above in accordance with its regional cost allocation methodology, as applied to ITPs.

2. Selection by at Least Two but Fewer than All Relevant Regions

If WestConnect (if it is a Relevant Planning Region) and at least one, but fewer than all, of the other Relevant Planning Regions select the ITP in their respective regional transmission plans for purposes of Interregional Cost Allocation, WestConnect is to evaluate (or reevaluate, as the case may be) pursuant to Sections VII.E.2(d), VII.E.2(e), and VII.E.2(f) above whether, without the participation of the non-selecting Relevant Planning Region(s), the ITP is selected (or remains selected, as the case may be) in its regional transmission plan for purposes for Interregional Cost Allocation. Such reevaluation(s) are to be repeated as many times as necessary until the number of selecting Relevant Planning Regions does not change with such reevaluation.

If following such evaluation (or reevaluation), the number of selecting Relevant Planning Regions does not change and the ITP remains selected for purposes of Interregional Cost Allocation in the respective regional transmission plans of WestConnect and at least one other Relevant Planning Region, WestConnect is to apply its regional cost allocation methodology to the projected costs of the ITP assigned to it under Sections VII.E.2(d) or VII.E.2(e) above in accordance with its regional cost allocation methodology, as applied to ITPs.

VIII. Recovery of Planning Costs

Tri-State's costs associated with the Regional Planning Process, including WestConnect's participation in interregional planning under Part VII, shall be recovered through existing rate structures. The costs for any local economic planning study shall be paid for by the Requester of those studies, as set forth in Section II.D.6. Any costs incurred by stakeholders for their participation in the Tri-State local planning processes shall be borne by those stakeholders.

For the costs of studies associated with specific wholesale delivery point requests by NITS or PTP customers taking service under the OATT, the requesting customer shall be responsible for the actual costs of such studies. The customer shall pay the full estimated cost prior to Tri-State begi

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 2000
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT L

Creditworthiness Procedures

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service under the Transmission Provider's Tariff, Transmission Provider will require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices using quantitative and qualitative criteria to determine the level of secured and unsecured credit.

Transmission Customer must maintain a credit limit equal to or exceeding the historical, or estimated highest 60 day credit exposure. If the unsecured credit limit granted is insufficient, or unsecured credit is denied, the Applicant and/or Transmission Customer must provide collateral/security required by the Transmission Provider in a form and amount satisfactory to the Transmission Provider.

A. Summary of Credit Review Procedures

An initial credit analysis will be performed on all customers desiring to purchase service under the Tariff. The creditworthiness of the Transmission Customer or potential Transmission Customer (collectively, a "Transmission Customer") must be determined through a fundamental analysis of the Transmission Customer's financial and operational condition prior to receiving transmission service. Transmission Provider's Credit Risk Administrator analyzes the financial strength of credit applicants based on both quantitative and qualitative criteria and makes a subsequent decision that is communicated to the Oasis Administrator, which is responsible for administering transmission service under the Tariff. Any Transmission Customer must satisfy the requirements of Transmission Provider's Creditworthiness Procedures prior to receiving transmission service.

Except as required by regulation or law, applicant credit information is not released to outside third parties.

The credit analysis can include applicant supplied and/or independently obtained data from sources such as trade references, bank references, annual audited and quarterly financial statements, SEC filings, FERC applications or approvals, Dun & Bradstreet reports, Value-Line Investment Surveys, Standard & Poor's "S&P", Moody's, Fitch, trade publications, and industry contacts.

Examples of the criteria used in the credit review process include, but are not limited to, the following:

Quantitative Criteria:

a. Financial ratios (capitalization metrics, equity and asset metrics, operating and net margin metrics, tangible net worth metrics, debt and interest coverage metrics, cash flow metrics, etc.)
b. Financial trends (year to year, quarter to quarter, etc.)
c. Credit Ratings from S&P, Moody's or Fitch

Qualitative Criteria:

a. Power supply portfolio
b. Rate policy/ ability to set and maintain rates to recover cost
c. Management reputation
d. Risk profile of industry classification
e. Corporate strategy/reputation
f. Credit risk management capability
g. Past or present performance under credit or loan agreements

B. Qualification for Unsecured Credit

Transmission Customers may apply for unsecured credit by completing a Credit Application available on the Transmission Provider's OASIS. Transmission Provider's Credit Risk Administrator will make reasonable efforts to review the Credit Application or request additional information if required within ten (10) business days of receipt. Failure to submit all the required information may result in a delay of the credit review and approval. There are two methods for Transmission Customers to potentially qualify for unsecured credit with Transmission Provider.

Qualification Method 1:

Following are the criteria that must be satisfied for qualification under Qualification Method 1:

i. The Transmission Customer is (i) an investor-owned utility ("IOU"), public power district, municipal utility, rural electric cooperative, or distribution utility and (ii) has the direct authority to establish and adjust rates to recover costs, including power costs, without seeking approval from a regulatory agency; and
ii. The Transmission Customer is not currently in payment default to Transmission Provider or another known party and has not been in

payment default to Transmission Provider or another known party during the prior 3 years; and

iii. The Transmission Customer has not experienced a material adverse change in its financial condition or payment practices during the prior year.

Transmission Customers qualifying for credit under Method 1 may alternatively choose to be evaluated for a higher credit limit under Method 2. Transmission Customers who qualify for unsecured credit under Method 1 will be assigned a $1 million unsecured credit limit. Transmission Customers who do not meet the Qualification Method 1 criteria may apply for credit under Qualification Method 2 or provide credit support security to Transmission Provider as set forth in Section C below. Transmission Customers who qualify for unsecured credit under Qualification Method 1, but whose total credit exposure exceeds or is expected to exceed their unsecured credit limit of $1 million will be required to apply for credit under Qualification Method 2 or provide additional credit support security as set forth in Section C below. All Transmission Customers qualifying under Method 1 will be re-evaluated for creditworthiness at least annually, or more frequently if the Transmission Provider has commercially reasonable grounds to believe there has been a material adverse change in the Transmission Customer's creditworthiness, and can be required to provide updated financial information to Transmission Provider's Credit Risk Administrator.

Qualification Method 2:
To qualify for credit under Qualification Method 2, Transmission Customers must not currently be in payment default to Transmission Provider or another known party and not have been in payment default to Transmission Provider or another known party during the prior 3 years and must undergo a comprehensive creditworthiness evaluation. Both quantitative and qualitative criteria will be evaluated. These Transmission Customers are required to provide the following information:

i. Three years of audited financial statements including income statement, balance sheet, cash flow statements, and accompanying footnotes (Transmission Customers without three years of audited financial statements should provide the maximum number of years available).

Transmission Customers that apply for unsecured credit under Method 2 will be evaluated in part based on their credit ratings by S&P, Moody's and/or Fitch credit rating agencies. Alternatively, Transmission Provider will assign an internal credit rating to Transmission Customers based on both quantitative and qualitative criteria, which such rating shall follow the same scale as S&P (e.g. AAA, AA, A, BBB, BB, etc.).

Transmission Customers with S&P, Moody's, Fitch or Transmission Provider internal Credit Ratings of investment grade or higher will qualify for unsecured credit under Qualification Method 2. If a Transmission Customer is rated by more than two credit rating agencies, the lower of the highest two ratings will be used. The unsecured credit limit assigned is defined in the table below. Transmission Customers rated below investment grade will need to provide an acceptable form of credit support security as set forth in Section C below.

S&P/Fitch/Transmission Provider	**Moody's**	**Credit Limit (in $Million)**	**Adjustments ($Million)**
A to AAA	**A2 to Aaa**	**$10**	**+/- $2.5**
A-	**A3**	**$7.5**	**+/- $2.5**
BBB+	**Baa1**	**$5.0**	**+/- $2.5**
BBB	**Baa2**	**$2.5**	**+/- $2.5**
BBB-	**Baa3**	**$0**	**+/- $2.5**

Adjustment Criteria to the table above includes:

a. Positive adjustments in the Adjustments column of the table above will be applied to IOU/public power/municipal/ rural electric cooperative /distribution utility, which have the ability to set and adjust rates to recover costs, including power costs, without seeking approval from a regulatory agency.

b. Negative adjustments in the Adjustment column of the table above will be applied to Transmission Customers that have negative financial trends.

c. Negative adjustments will also be applied to Transmission Customers that have had a material adverse change or have had a change in financial condition or payment practices.

All Transmission Customers qualifying under Method 2 will be re-evaluated for creditworthiness at least annually, or more frequently if the Transmission Provider has commercially reasonable grounds to believe there has been a material adverse change in the Transmission Customer's creditworthiness, and may be required to provide updated financial information to the Transmission Provider's Credit Risk Administrator. Notwithstanding any other statement in these Creditworthiness Business Procedures, if a Transmission Customer, its affiliate, or Credit Provider is in default of a payment obligation with Transmission Provider or another known party, Transmission Provider may, without notice to Transmission Customer, set the Transmission Customer's

unsecured credit limit at $0.

C. List of Acceptable Forms of Credit Support Security

Acceptable Credit Support Security could include one or a combination of the following, at Transmission Provider's discretion:

a. Parental guaranty, in a form acceptable to Transmission Provider, from an entity meeting the criteria under Qualification Method 2 above

b. Unconditional and irrevocable letter of credit, in a form provided by Transmission Provider, from an issuer satisfying the following requirements:

   i. Issuer must be a U.S. commercial bank or a licensed U.S. branch of a foreign bank;

   ii. Issuer must maintain an unsecured or issuer rating equivalent to A- or better as determined by at least two (2) rating agencies, one of which must be either Standard & Poor's or Moody's; and

   iii. Issuer must have total asset value of at least thirty billion dollars ($30,000,000,000.00)

c. Prepayment arrangement

d. Other form of credit support security acceptable to Transmission Provider

To the extent any of the credit support security expires prior to the transmission service agreement expiration date, the credit support security is required to be extended (with proof provided to Transmission Provider) not less than thirty (30) days prior to that expiration date of the credit support security for a period of at least three hundred and sixty (360) days. If a Transmission Customer fails to maintain or renew a letter of credit, Transmission Provider shall have the right to draw upon the entire undrawn portion of the letter of credit, without notice, and hold such cash as security. If the credit support security currently being used by a Transmission Customer is determined to no longer be considered acceptable after an annual or periodic credit review process, Transmission Provider will notify the Transmission Customer, who will be required to provide another form of credit support security within ten (10) days. The failure to maintain, renew, or provide substitute or additional credit support security when required will be considered a material breach of the transmission service agreement, may result in the forfeiture of any deposits made under the transmission service agreement.

If a Transmission Customer qualifies for credit based on the credit standing of a guarantor, letter of credit provider, or other form of credit support security with an explicit dollar limit set forth in such document, the credit limit assigned to the

Transmission Customer will be limited by the dollar limit in credit support security provided, but not surpassing the dollar limits stated in Section B above.

All costs associated with meeting Transmission Provider's credit risk requirements, including any costs of obtaining and posting credit support security, are the responsibility of the Transmission Customer.

D. Notification of Changes in Creditworthiness or Payment Status and Ability to Post Additional Credit Support Security

If Transmission Provider determines there is a downgrade in the creditworthiness of a Transmission Customer or a Transmission Customer’s guarantor, or in the event that a Transmission Customer is determined to be in Default Payment Status (defaults during the term of a transmission service agreement, or permanently defaults on a transmission service agreement), Transmission Provider will notify the Transmission Customer in writing. Such notification will include an explanation of the downgrade and new or additional credit support security requirements. Should Transmission Provider require the Transmission Customer to post new or additional credit support security, the Transmission Customer must post credit support security in an amount determined by Transmission Provider within five (5) business days of receipt of a written notification from Transmission Provider of a change in the creditworthiness of the Transmission Customer or Transmission Customer’s guarantor . If the Transmission Customer is determined to be in Default Payment Status, Transmission Provider will require additional credit support security to be provided for the remaining term of the transmission service agreement. This security also will apply to any guarantor or affiliate of the Transmission Customer, and to any successor or assignee of the Transmission Customer’s transmission service agreement. Additionally, if the Transmission Customer is determined to be in default in accordance with the provisions of Transmission Provider’s Tariff, Transmission Provider reserves the right to take any and all actions provided for under its Tariff.

E. Contesting Credit Determinations

The Transmission Customer has the opportunity to contest Transmission Provider’s determination of Transmission Customer’s creditworthiness or credit support security requirements in accordance with the dispute resolution procedure outlined within the Tariff. The Transmission Customer must still provide any require credit security support requirements, within the indicated time periods, as stated in the Tariff, while the review and response is in process.

F. Transmission Customer Default

If a Transmission Customer defaults in the performance of its obligations under the Tariff, Transmission Provider shall have the unconditional right to: (a) off-set all of the Transmission Customer's obligations under the Tariff against any credit support security held by Transmission Provider to secure the Transmission Customer's obligations; and (b) withhold payment of any obligation owed by Transmission Provider to the Transmission Customer regardless of how such obligation shall have arisen. Transmission Provider's right to withhold payment shall extend up to, and include, an amount equal to the sum of all obligations owed by Transmission Customer to Transmission Provider under any transmission service agreements and shall include the unconditional right to off-set such amount owed to the Transmission Customer against any obligation(s) due from the Transmission Customer to Transmission Provider. Transmission Provider shall provide the Transmission Customer with written notification of any off-set pursuant to this paragraph.

If a Transmission Customer that is party to a transmission service agreement fails to provide any credit support security as set forth herein, including fails to maintain, renew, or provide substitute or additional credit support security when required, Transmission Provider may refuse, without notice, to accept that Transmission Customer's transmission service schedule(s) or transmission service reservation(s) on Transmission Provider's OASIS until such time as that Transmission Customer provides Transmission Provider with credit support security that satisfies the requirements of this Attachment L and is otherwise acceptable to Transmission Provider.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
, Open Access Transmission Tariff, 1.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2019-09-21
Priority Order: 2010
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

Attachment M

Tri-State Generation and Transmission Association, Inc.

Transmission Formula Rate Implementation Protocols

Section I Annual Update

1. The transmission Formula Rate Template of Tri-State Generation and

Transmission Association, Inc. (Tri-State) and these Transmission Formula Rate Implementation Protocols (Protocols) together comprise the filed rate (Formula Rate) of Tri-State for its transmission system located in the Western Interconnection. Tri-State must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements (ATRR) and the rates for Network Integration Transmission Service (NITS), Point-to-Point (PTP) Transmission Service, and Ancillary Services for its Eligible Facilities located in the Western Interconnection.

Recovery of costs associated with existing and new facilities shall be consistent with the Formula Rate and the methodology for determining what facilities qualify for inclusion in the Formula Rate ("Eligible Facilities") as defined in Section II below. The ATRR shall be determined using the financial and usage data for January 1 to December 31 of a given Calendar Year. The Formula Rate shall become effective for recovery of Tri-State's ATRR upon the Effective Date.

2. The Formula Rate shall be applicable to service on and after October 1 of each Calendar Year through September 30 of the following Calendar Year (Rate Year), (with the exception of the first Rate Year being Effective Date-September 30, 2020) subject to review, challenge and refunds or surcharges with interest, to the extent provided herein.

3. On or before July 15 of each Calendar Year, Tri-State shall:

   (a) Recalculate the ATRR and the rates for NITS service for the new Rate Year in accordance with the Formula Rate (Annual Update); and

(b) Post its Annual Update to the Tri-State OASIS; and

(c) If the date for posting the Annual Update falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's Initial Posting Date. Any delay in the Initial Posting Date shall result in an equivalent extension of time for the submission of Information Requests.

4. Concurrent with the Annual Update postings, Tri-State shall provide a notice of such posting via an email distribution list to all Interested Parties.

5. The Annual Update shall:

(a) Include a workable populated Formula Rate Template with fully functional spreadsheets showing the calculation of the Annual Update and underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data;

(b) Be based on the independently-audited books and records of Tri-State for the most recent fiscal year including its Rural Utilities Service ("RUS") Financial and Operating Report or successor reports including the RUS Financial and Operating Report Electric Power Supply prepared consistent with RUS requirements but not filed with RUS for the first Rate Year Effective Date- September 30, 2020 and the FERC Form 1 for Rate Year's thereafter (January 1 through December 31);

(c) Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rate;

(d) Identify any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate. Tri-State shall identify:

i. Any accounting changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR. Any items included in the Formula Rate at an amount other than a historic cost basis.

ii. Individual impact of any changes in i above on charges billed under the Formula Rate.

(e) Not seek to modify the Formula Rate.

Section II Definitions

For purposes of these Protocols, the following capitalized terms shall have the meanings set forth below.

(a) "Accounting Change" means any change in Tri-State's accounting policies and practices from those in effect for the Calendar Year upon which the immediately preceding Annual Update was based and that could impact the ATRR calculations under the Formula. Accounting Changes include any changes resulting from:

(i) revisions to the USoA; (ii) revisions to FERC Form 1 data and the

requirement to report certain values within it; (iii) correction of errors and prior period adjustments that impact the ATRR; (iv) the implementation of new estimation methods or policies; (v) changes to income tax elections; (vi) changes in accounting practices or policies mandated by a state regulatory authority with jurisdiction over Tri-State that could impact the Formula Rate or calculations under the Formula Rate; (vii) implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction; (viii) a change in Tri-State's accounting policies and practices (as such changes are defined by the Statement of Financial Accounting Board Standards No. 154 issued by the Financial Accounting Standards Board or its successor); (ix) Tri-State's own accounting changes (which constitute a change to the ATRR greater than or equal to $50,000) such as the addition or deletion of a subaccount not specified by the USoA; or (x) a change in Tri-State's inter-corporate cost allocation policies or practices from those policies and/or practices in effect in the Prior Rate Year, which change causes a result under the Formula Rate different than the result under the Formula Rate as calculated without such change.

(b) "Annual Transmission Revenue Requirement" (ATRR) means the net revenue requirement for the Transmission Services calculated in accordance with the Formula Rate filed by Tri-State for informational purposes with the

Commission and posted on the Tri-State OASIS on or before the annual Initial Posting subject to review pursuant to the provisions of these Protocols.

(c) “Annual Meeting” means the meeting hosted by Tri-State for the purpose of exchanging information with Interested Parties regarding the Formula Rate.

(d) “Annual Update” means Tri-State’s annual filing of its Formula Rate, in a working Excel™ format. The Annual Update is submitted as described in these Protocols.

(e) “Business Day” means from 9:00 AM to 5:00 PM Mountain Prevailing Time other than weekends and Federal Holidays.

(f) “Calendar Year” means January 1 through December 31 of a given year.

(g) “Current Rate Year” means the Rate Year for which the Annual Update is posted on the Tri-State OASIS and which Tri-State has filed with the Commission (*e.g.*, if the Annual Update is filed on October 1, 2019, the Current Rate Year is October 1, 2019 through September 30, 2020).

(h) “Customer(s)” or “Transmission Customer(s)” means the customers taking NITS service, service under Grandfathered Agreements, or PTP service.

(i) “Eligible Facilities" A Transmission Facility is a facility that is included as part of the Transmission System that meets any of the following criteria:

1. All existing non-radial power lines, substations, and associated facilities, operated at 100 kV or above, plus all radial lines and

associated facilities operated at or above 100 kV that serve two or more Eligible Customers not Affiliates of each other.

2. For a substation connected to the Transmission System, where power is transformed from a voltage higher than 100 kV to a voltage lower than 100 kV, the facilities on the high voltage side of the transformer will be included with the exception of transformer isolation equipment.

3. A facility operated below 100 kV that has been determined to be transmission by the Commission pursuant to the seven (7) factor test set forth in Commission Order No. 888, 61 Fed Reg. 21,540, 21,620 (1996), or any applicable successor test.

(j) "FERC" or "Commission" means the Federal Energy Regulatory Commission.

(k) "Final Posting" means the annual update information posted to the Tri-State OASIS with changes agreed to during the informal review process.

(l) "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is filed with the Commission, and served on Tri-State by electronic service on the date of such filing.

(m) "Formula Rate Template" means the Tri-State transmission formula rate template set forth herein.

(n) "Formula" means the Formula Rate Template set forth herein.

(o) "Formula Rate" means the Tri-State Implementation Protocols together with the Formula Rate Template.

(p) "FPA" means Federal Power Act.

(q) "Informal Challenge" means written notification by an Interested Party to Tri-State, during the Review Period, of any specific challenge to the Annual Update.

(r) "Information Request" means a written request submitted by an Interested Party to Tri-State.

(s) "Informational Filing" means Tri-State's annual filing at the Commission with the information stipulated in these Protocols.

(t) "Initial Posting" means the Annual Update data and information which Tri-State posts to the Tri-State OASIS. The Initial Posting date for each year shall be no later than July 15, provided, however, that if July 15 should fall on a weekend or a holiday recognized by the Commission, then the posting shall be due no later than the next Business Day, and the Publication Date shall be the actual posting date.

(u) "Interest" means interest calculated pursuant to 18 C.F.R. § 35.19a (a) (2) (iii), or successor regulation.

(v) "Interested Party" includes but is not limited to, customers under the Tri-State Tariff, state utility regulatory commissions, and state attorneys general.

(w) "NITS" means Network Integration Transmission Service as defined in the Tri-State Tariff.

(x) "OATT" or "Tri-State Tariff "means Tri-State's Open Access Transmission

Tariff.

(y) "OASIS" means Open Access Same-Time Information System.
(z) "Prior Rate Year" means the Rate Year prior to the Current Rate Year (*e.g.*, if the Current Rate Year is October 1, 2019 through September 30, 2020, then the Prior Rate Year is October 1, 2018 through September 30, 2019).
(aa) "PTP Rates" means the point-to-point rates derived from the Formula Rate.
(bb) "Rate Year" means October 1 of a given year through September 30 of the subsequent year.
(cc) "Review Period" means, unless otherwise extended in writing by Tri-State, 60 days after the Initial Posting. During the Review Period Interested Parties may serve reasonable information requests on Tri-State.
(dd) "USoA" means Uniform System of Accounts.

Section III Review of Annual Update

Within twenty (20) days of the Initial Posting date of Tri-State' Annual Update, Tri-State will host a meeting for Interested Parties to discuss the Annual Update (Annual Meeting). Tri-State shall provide notice of this meeting concurrent with the posting of the Formula Rate Update accessible on the Tri-State OASIS. The notice shall include the date, time and location of the Annual Meeting and also shall be provided via email distribution list of Interested Parties. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically from the OASIS.

A. Information Exchange

Interested Parties may begin submitting information requests immediately following the Initial Posting date of the Annual Rate Update and will have until sixty (60) days after the date of the Initial Posting to serve reasonable information

requests on Tri-State for information and work papers supporting the Annual Rate Update. Such information requests shall be limited to that what is necessary to determine:

(a) The extent or effect of an accounting change;

(b) Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

(c) The proper application of the Formula Rate and procedures in these Protocols;

(d) The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

(e) The effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

(f) Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

The information and document requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable.

2. Tri-State shall make a good faith effort to respond to information requests pertaining to the Annual Update within fourteen (14) business days of receipt.

3. Tri-State shall post on its OASIS all information requests from Interested Parties and Tri-State' response(s) to such requests. If responses to

information requests contain information deemed by Tri-State to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and Tri-State.

B. Informal Challenge Procedures

1. Interested Parties shall have until September 15 (or the first Business Day after September 15 if September 15 falls on a weekend or holiday) to notify Tri-State in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its Informal Challenge. Tri-State will make a good faith effort to respond to any Informal Challenge within twenty (20) days of notification of such Informal Challenge. Tri-State shall appoint representatives to work with the Interested Party to resolve the Informal Challenge.

2. Tri-State will post on its OASIS all Informal Challenges from Interested Parties and Tri-State' responses to the Informal Challenges. If responses to information requests contain information deemed by Tri-State to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and Tri-State.

3. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge procedures that are agreed to by Tri-State and resolved prior to the end of the review period shall be reported in the Final Posting on the Tri-State OASIS. Any changes or adjustments agreed to by Tri-State after this date will be reported in the Informational Filing made with FERC and will be reflected in the Annual Rate Update for the following Rate Year.

C. Formal Challenges.

1. A Formal Challenge shall:

(a) Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;

(b) Explain how the action or inaction violates the filed Formula Rate or Protocols;

(c) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an accounting change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rate and procedures in these Protocols;

iv. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

v. The effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

vi. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;

(g) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

(h) State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

2. Formal Challenges shall be filed with FERC, either in the FERC Docket assigned to the Informational Filing or via Section 206 of the FPA, and shall be served upon Tri-State contemporaneously with the filing at FERC. Service can be accomplished by electronic mail in accordance with § 385.2010(f) (3), express delivery or messenger to the individual listed as the contact person in Tri-State' Informational Filing.

D. Modification of Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols and the Annual Update shall not be subject to challenge for the purpose of modifying the Formula Rate.

2. A change to the Formula Rate fixed inputs related to rate of return on equity (ROE), depreciation rates, capital structure, amortization periods, and any ROE incentives may not be made absent the appropriate filing with FERC pursuant to the FPA Sections 205 or 206.

3. If Tri-State makes a correction to a Mistake in its financial information during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in accordance with the Tri-State Tariff. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as arithmetic or

computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

4. Any changes to the data inputs or as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any interest on any refund shall be calculated in accordance with the Tri-State Tariff.

5. The Federal Energy Regulatory Commission ("FERC" or "Commission") annually determines the FERC Annual Charge and Tri-State assesses the charge to its Transmission Customers. The FERC Annual Charge is shown on the Formula Rate Template rate sheet for ease of reference but it is a pass through of the FERC-calculated charge and is not part of the Formula Rate calculations.

E. FERC Informational Filing.

1. By October 15th of each year, Tri-State shall submit to FERC an informational filing (Informational Filing) of its Annual Update.

2. This Informational Filing must include the information that is reasonably necessary to determine:

   (a) That input data under the Formula Rate is properly recorded in any underlying work papers;

(b) That Tri-State has properly applied the Formula Rate and these procedures;

(c) The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and

(d) The extent of accounting changes that affect Formula Rate inputs.

3. The Informational Filing must also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Informational Filing, Tri-State shall provide notice of the Informational Filing to Interested Parties via the email and by posting the docket number assigned to the Informational filing on the Tri-State OASIS.

Section IV Tri-State Example Schedule (Nominal last dates):

Action	**Date**
Initial Posting (Tri-State OASIS)	July 15
Annual Meeting, Interested Parties (20 days)	August 4
Interested Parties Review Period (60 days)	September 13
Informal Challenges Due Date Ending	September 13
Final Posting (Tri-State OASIS)	September 20
Rate Year	October 1-September 30
Informational Filing	October 15

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

INDEX

Data:

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Point-to-Point, Schedule 1, and Schedule 2 Transmission Rates and Schedule 10 - Facility Charge Rate

Data:

A Line	B Description	C Reference	D Allocated Amount
1	**Annual Transmission Revenue Requirement**		
2	Net Annual Transmission Revenue Requirement	Summary, Line 12, Col H	#DIV/0!
3			
4	**System Load (kW)**		
5	12 Month Average Transmission System Peak	Worksheet D, Line 14, Col E	-
6			
7	**Point-to-Point Transmission Rates - $/kW**		
8	$ / kW-Year	(D2/ D5)	#DIV/0!
9	$ / kW-Month	(D8 / 12 months)	#DIV/0!
10	$ / kW per Week	(D8 / 52 weeks)	#DIV/0!
11	$ / kW per Day	(D8 / 312 days)	#DIV/0!
12	mills per kWh--Firm and ONPEAK non-firm	(D8 / 4,160 hours * 1,000)	#DIV/0!
13	mills per kWh--OFFPEAK non-firm	(D8 / 8,760 hours * 1,000)	#DIV/0!
14	**Schedule 1 - Annual Revenue Requirement**		
15	Net Schedule 1 Revenue Requirement	Schedule 1, Line 18, Col H	#DIV/0!
16			
17	**System Load (kW)**		
18	12 Month Average Transmission System Peak	Worksheet D, Line 14, Col E	-
19			
20	**Schedule 1 Rates - $/kW**		
21	$ / kW-Year	(D15 / D18)	#DIV/0!
22	$ / kW-Month	(D21 / 12 months)	#DIV/0!
23	$ / kW per Week	(D21 / 52 weeks)	#DIV/0!
24	$ / kW per Day	(D21 / 365 days)	#DIV/0!
25	mills per kWh	(D21 / 8,760 hours * 1,000)	#DIV/0!
26	**Schedule 2 - Reactive Supply and Voltage Control (VAR Support)**		
27	Net Schedule 2 Revenue Requirement	[Input Initial Filing No.	$

		Here]	2,543,530
28			
29	**System Load (kW)**		
30	12 Month Average Transmission System Peak	[Input Initial Filing No. Here]	2,332,915
31			
32	**Schedule 2 Rates - $/kW** (Note: A)		
33	$ / kW-Year	(D27 / D30)	$ 1.09028
34	$ / kW-Month	(D33 / 12 months)	$ 0.09086
35	$ / kW per Week	(D33/ 52 weeks)	$ 0.02097
36	$ / kW per Day	(D33 / 365 days)	$ 0.00299
37	mills per kWh	(D33 / 8,760 hours * 1,000)	$ 0.12446
	A.) These rates are fixed and cannot be changed absent authorization from FERC via a Section 205 or 206 filing.		

38	**FERC Annual Charge**		
39	FERC's annual charge per MWh is established by the Commission annually, and is assessed to the Transmission Owner, and is passed through to the Transmission Customers.		/MWh
40	-	-	-

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Summary of Total ATRR Revenue Requirement

Data:

A	B	C	D	E	F	G	H
Line	**Account**	**Description**	**Reference**	**Total Company**	**Allocation Factor**	**Allocation %**	**Transmission**
1		**A. Gross Revenue Requirement for Network Service**					
2		Transmission Costs	Worksheet B, Line 38, Col I				#DIV/0!
3		Revenue Credits-Operating					
4	454	Rental Income	Worksheet M, Line 24, Col D and F	$ -	Direct		$ -
5	456	Other Electric Revenue - Administrative Fee -TSR	Worksheet M, Line 25, Col D and F	$ -	Direct		$ -
6	456	Revenues from Transmission of Electricity of Others including ST Firm & Non-Firm	Worksheet M, Line 26, Col D	$ -	Direct		$ -
7	456	Other Electric Revenue - GFAs	Worksheet M, Line 27, Col F	$ -	Direct 100	100.000%	$ -
8	456	Other Electric Revenue	Worksheet M, Line 28, Col D	$ -	Direct Zero	0.000 %	$ -
9		Revenue Credits-Operating	Subtotal	$ -			$ -
10		Reconciliation Adjustments to ATRR	Worksheet J, Line 6, Col J				$ -
11		Reconciliation Adjustments to ATRR - Other	Worksheet J, Line 12, Col J				$ -
12		Net Annual Transmission Revenue Requirement	Line 2 - Line 9 + Lines 10 & 11				#DIV/0!

Tri-State Generation & Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE

Schedule 1 Revenue Requirement

Data:

A Line	B Account	C Description	D Reference	E Total Company	F Allocation Factor	G Allocation %	H Total Schedule 1
1	**DIRECT EXPENSE AMOUNTS**						
2	561	Load Dispatching	Worksheet G, Line 2, Col F	$0	T-Tran Plant	#DIV/0!	#DIV/0!
3	**ASSOCIATED LOAD DISPATCHING COSTS**						
4		**Expenses**					
5		Total Company Customer Accounting Expense	Worksheet B, Line 19, Col F	$0	T-Wage2	#DIV/0!	#DIV/0!
6		Total Company Administrative & General Expenses	Worksheet B, Line 28, Col F	$0	T-Wage2	#DIV/0!	#DIV/0!
7		Total Company General Plant Depreciation Expense	Worksheet F, Line 135, Col F	$0	T-Wage2	#DIV/0!	#DIV/0!
8		Total Company Intangible Plant Amortization Expense	Worksheet F, Line 146, Col F	$0	T-Wage2	#DIV/0!	#DIV/0!
9		**Total Expenses**	Sum Lines 5 thru 8	$0			#DIV/0!
10		**Return on General & Intangible Plant**					
11		Total Company Net Intangible Plant in Service	Worksheet A, Line 35, Col F	$0	T-Wage2	#DIV/0!	#DIV/0!
12		Total Company Net General Plant in Service	Worksheet A, Line 39, Col F	$0	T-Wage2	#DIV/0!	#DIV/0!
13		Total General & Intangible Plant	Sum Lines 11 and 12	$0			#DIV/0!
14		Weighted Rate of Return	Worksheet C, Line 5, Col K				#DIV/0!
15		Return on General & Intangible Plant	Line 13 * Line 14				#DIV/0!
16		**Total Associated Load Dispatching Costs**	Line 9 + Line 15				#DIV/0!
17	**SCHEDULE 1 REVENUE REQUIREMENT**						
18		**Net Schedule 1 Revenue Requirement for Zone**	Sum Lines 2 and 16				**#DIV/0!**

19	Load Dispatching Wages and Salaries	Worksheet E, Line 3, Col D	$0	T-Tran Plant	#DIV/0!	#DIV/0!
20	Total Wages and Salaries	Worksheet E, Line 8, Col D	$0	Direct100	100.00 %	$0
21	Schedule 1 Wages & Salaries Allocator	Line 19 / Line 20			**T-Wage2 =**	**#DIV/0!**

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Rate Base

Data:

A	B	C	D	E	F	G	H	I
Line	**Description**	**Reference**	**Beginning of Year**	**End of Year**	**Total Company**	**Allocation Factor**	**Allocation %**	**Transmission**
1	**Plant in Service**							
2	301-303 Total Intangible Plant	Worksheet F Line 72, Col D thru F	$ -	$ -	$ -	T-Wage Allocation	#DIV/0!	#DIV/0!
3	310 Steam Production Plant	Worksheet F Line 73, Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
4	320 Nuclear Production Plant	Worksheet F Line 74, Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
5	330 Hydro Production Plant	Worksheet F Line 75, Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
6	340 Other Production Plant	Worksheet F Line 76, Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
7	Total Production Plant	Subtotal	$ -	$ -	$ -			$ -
8	350 Land and Land Rights	Worksheet F Line 78, Col D thru F	$ -	$ -	$ -	T-Tran Lines	#DIV/0!	#DIV/0!
9	352 Structures and Improvements	Worksheet F Line 79, Col D thru F	$ -	$ -	$ -	T-Tran Stations	#DIV/0!	#DIV/0!
10	353 Station Equipment	Worksheet F Line 80, Col D thru F	$ -	$ -	$ -	T-Tran Stations	#DIV/0!	#DIV/0!
11	354 thru 359.1 Other Transmission Plant	Worksheet F Line 81, Col D thru F	$ -	$ -	$ -	T-Tran Lines	#DIV/0!	#DIV/0!
12	Transmission Plant	Subtotal	$ -	$ -	$ -			#DIV/0!
13	360 Land and Land Rights	Worksheet F Line 83, Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
14	361 Structures and Improvements	Worksheet F Line 84, Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
15	362 Station Equipment	Worksheet F Line 85, Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
16	363-374 Other Distribution Plant	Worksheet F Line 86, Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
17	Total Distribution Plant	Subtotal	$ -	$ -	$ -			$ -
18	380-386 RTO/ISO Plant	Worksheet F, Line 88 Col F	$ -	$ -	$ -	T-Tran Plant	#DIV/0!	#DIV/0!
19	389 thru 399.1 Total General Plant	Worksheet F, Line 89 Col F	$ -	$ -	$ -	T-Wages	#DIV/0!	#DIV/0!

20	106 Completed Construction Not Classified	Worksheet F Line 94, Col D thru F and Worksheet Q Line 1 Col I	$ -	$ -	$ -	Direct		$ -
21	Gross Electric Plant in Service	Subtotal	$ -	$ -	$ -			#DIV/0!
22	**Accumulated Depreciation**							
23	108.1 Depr Rsv. of Steam Plant	Worksheet F, Line 101 Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
24	108.2 Depr Rsv. of Nuclear Plant	Worksheet F, Line 102 Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
25	108.3 Depr Rsv. of Hydraulic Plant	Worksheet F, Line 103 Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
26	108.4 Depr Rsv. of Other Prod Plant	Worksheet F, Line 104 Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
27	Total Production Reserve	Sum	$ -	$ -	$ -			$ -
28	108.5 Depreciation of Transmission Plant	Worksheet F Line 105, Col D thru F and (Worksheet V Cols J and L Line 10 + Worksheet U Cols J and L Line 10)/2	$ -	$ -	$ -	Direct		$ -
29	108.6 Depreciation of Distribution Plant	Worksheet F, Line 106 Col D thru F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
30	108.7 Depreciation of General Plant	Worksheet F, Line 107 Col D thru F	$ -	$ -	$ -	T-Wage Allocation	#DIV/0!	#DIV/0!
31	108.8 Retirement Work in Progress	Worksheet F Line 108, Col D thru F and Worksheet T Line 1 Col J	$ -	$ -	$ -	Direct		$ -
32	111 Amort of Electric Plant in Service	Worksheet F, Line 109 Col D thru F	$ -	$ -	$ -	T-Wage Allocation	#DIV/0!	#DIV/0!
33	Total Accumulated Depreciation	Sum	$ -	$ -	$ -			#DIV/0!
34	**Total Net Plant in Service**							
35	301-303 Net Total Intangible Plant	Line 2 - Line 32	$ -	$ -	$ -			#DIV/0!
36	Net Production Plant	Line 7 - Line 27	$ -	$ -	$ -			$ -
37	Net Transmission Plant	Line 12 + Line 18 - Line 28	$ -	$ -	$ -			#DIV/0!
38	Net Distribution Plant	Line 17 - Line 29	$ -	$ -	$ -			$ -
39	Net General Plant	Line 19 - Line 30	$ -	$ -	$ -			#DIV/0!
40	Net Completed Construction Not Classified	Line 20	$ -	$ -	$ -			$ -
41	108.8 Retirement Work in Progress	Line 31	$ -	$ -	$ -			$ -
42	Total Net Plant in Service	Sum	$ -	$ -	$ -			#DIV/0!
43	Adjustments to Rate Base							
44	105 Electric Plant Held For Future Use - Production	Worksheet N Line 1, Cols E, H, and K	$ -	$ -	$ -	Direct Zero	0.000 %	$ -

45	105 Electric Plant Held For Future Use - Transmission	Worksheet N Line 16, Cols E, H, and K	$ -	$ -	$ -		Direct		$ -
46	105 Electric Plant Held For Future Use - Distribution	Worksheet N Line 17, Cols E, H, and K	$ -	$ -	$ -		Direct Zero	0.000 %	$ -
47	105 Electric Plant Held for Future Use - General	Worksheet N Line 18, Cols E, H, and K	$ -	$ -	$ -		T-Wage Allocation	#DIV/0!	#DIV/0!
48	105 Electric Plant Held for Future Use - Intangible	Worksheet N Line 19, Cols E, H, and K	$ -	$ -	$ -		T-Wage Allocation	#DIV/0!	#DIV/0!
49	107 Construction Work in Progress	Worksheet F Line 98, Col D thru F and Worksheet R Line 1 Col K	$ -	$ -	$ -		Direct		#DIV/0!
50	Working Capital								
51	Total Transmission O&M Costs	Worksheet B, Line 29, Col F and I			$ -				#DIV/0!
52	Billing Lag in Days	Worksheet F, Line 1 Col F				45			45
53	Working Capital	Line 51 * Line 52 / 365			$ -				#DIV/0!
54	Prepayments	Worksheet F, Line 61, Col D thru F	$ -	$ -	$ -		T-Plant Allocation	#DIV/0!	#DIV/0!
55	M&S Coal	Worksheet F, Line 113 Col D thru F	$ -	$ -	$ -		Direct Zero	0.000 %	$ -
56	M&S Other Fuel	Worksheet F, Line 114 Col D thru F	$ -	$ -	$ -		Direct Zero	0.000 %	$ -
57	M&S Production Plant Parts	Worksheet F, Line 115 Col D thru F	$ -	$ -	$ -		Direct Zero	0.000 %	$ -
58	M&S Station Transformers & Equipment	Worksheet F, Line 116 Col D thru F	$ -	$ -	$ -		T-Tran Stations	#DIV/0!	#DIV/0!
59	M&S Line Materials & Supplies	Worksheet F, Line 117 Col D thru F	$ -	$ -	$ -		T-Tran Lines	#DIV/0!	#DIV/0!
60	M&S Other	Worksheet F, Line 118 Col D thru F	$ -	$ -	$ -		T-Plant Allocation	#DIV/0!	#DIV/0!
61	Materials and Supplies	Sum	$ -	$ -	$ -				#DIV/0!
62	Network Upgrades Credit	Worksheet H, Line 1, Col G	$ -	$ -	$ -		Direct		$ -
63	Total Working Capital and Adjustments				$ -				#DIV/0!
64	Rate Base	Total			$ -				#DIV/0!

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
O&M, Depreciation, and
Return Expenses

Data:

A	B	C	D	E	F	G	H	I
Line	**Description**	**Reference**	**Total Company**	**Total Company**	**Total Company**	**Allocation Factor**	**Allocation %**	**Transmission ATRR West**
1	Transmission Operation & Maintenance Expenses		Lines	Stations				
2	560 Supervision and Engineering	Worksheet G, Line 1 Cols D Thru F	$ -	$ -	$ -	T-Tran Plant	#DIV/0!	#DIV/0!
3	561 Load Dispatching	Worksheet G, Line 2 Cols D and F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
4	562 Station Expenses	Worksheet G, Line 3 Cols E Thru F	$ -	$ -	$ -	T-Tran Stations	#DIV/0!	#DIV/0!
5	563 Overhead Line Expenses	Worksheet G, Line 4 Cols D and F	$ -	$ -	$ -	T-Tran Lines	#DIV/0!	#DIV/0!
6	564 Underground Line Expenses	Worksheet G, Line 5 Cols D and F	$ -	$ -	$ -	T-Tran Lines	#DIV/0!	#DIV/0!
7	565 Transmission of Electricity by others	Worksheet G, Line 8 Cols D and F and Worksheet O, Line 7, Col F	$ -	$ -	$ -	Direct Zero	0.000 %	$ -
8	566 Miscellaneous Expenses	Worksheet G, Line 6 Cols D Thru F	$ -	$ -	$ -	T-Tran Plant	#DIV/0!	#DIV/0!
9	567 Rents	Worksheet G, Line 9 Cols D Thru F	$ -	$ -	$ -	T-Tran Stations	#DIV/0!	#DIV/0!
10	568 Supervision and Engineering	Worksheet G, Line 11 Cols D Thru F	$ -	$ -	$ -	T-Tran Plant	#DIV/0!	#DIV/0!
11	569 Structures	Worksheet G, Line 12 Cols E Thru F		$ -	$ -	T-Tran Stations	#DIV/0!	#DIV/0!
12	570 Station Equipment	Worksheet G, Line 13 Cols E Thru F		$ -	$ -	T-Tran Stations	#DIV/0!	#DIV/0!
13	571 Overhead Lines	Worksheet G, Line 14 Cols D and F	$ -		$ -	T-Tran Lines	#DIV/0!	#DIV/0!
14	572 Underground Lines	Worksheet G, Line 15 Cols D and F	$ -		$ -	T-Tran Lines	#DIV/0!	#DIV/0!
15	573 Miscellaneous Transmission Plant	Worksheet G, Line 16 Cols D Thru F	$ -	$ -	$ -	T-Tran Plant	#DIV/0!	#DIV/0!
16	575.1-575.8 RTO/ISO Expense - Operation	Worksheet P, Line 2, Col F	$ -		$ -	Direct 100	100.000%	$ -
17	576.1-576.5 RTO/ISO Expense - Maintenance	Worksheet P, Line 4, Col F	$ -		$ -	Direct 100	100.000%	$ -
18	Transmission O&M	Subtotal	$ -	$ -	$ -			#DIV/0!
19	Customer Accounting	Worksheet F, Line 27 Col F			$ -	T-Wage Allocation	#DIV/0!	#DIV/0!
20	Customer Services & Information	Worksheet F, Line 28 Col F			$ -	Direct Zero	0.000 %	$ -
21	Sales	Worksheet F, Line 29 Col F			$ -	Direct Zero	0.000 %	$ -

22	Customer Related Expense	Subtotal			$ -			#DIV/0!
23	Administrative & General Expense							
24	Admin and General Expense	Worksheet F, Line 30 Col F Less Line 25 and Line 26			$ -	T-Wage Allocation	#DIV/0!	#DIV/0!
25	Account 928 Expenses - West	Worksheet S, Line 4, Col F			$ -	Direct 100	100.000%	$ -
26	Account 928 Expenses - East	Worksheet S, Line 4, Col E			$ -	Direct Zero	0.000%	$ -
27	Maintenance Expense General Plant	Worksheet F, Line 37 Col F			$ -	T-Wage Allocation	#DIV/0!	#DIV/0!
28	Total A&G Expenses	Subtotal			$ -			#DIV/0!
29	Subtotal O&M				$ -			#DIV/0!
			Total Company	Adjustment	Adjusted Total			
30	Depreciation Expense							
31	Depreciation Expense-Trans	Worksheet L, Line 11 Col H				Direct		$ -
32	Depreciation Expense-General	Worksheet L, Line 42 Col J				Direct		#DIV/0!
33	Amort of Intangible Plant	Worksheet L, Line 45 Col J				Direct		#DIV/0!
34	Total Depreciation & Amortization	Subtotal						#DIV/0!
35	Taxes	Worksheet F, Line 41 Col F	$ -			T-Net Allocation	#DIV/0!	#DIV/0!
36	Return	Worksheet C, Line 7, Col K						#DIV/0!
37	Network Upgrades Interest Expense					Direct		$ -
38	Revenue Requirement before revenue credits							#DIV/0!

Tri-State Generation and Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE

Return

Data:

A	B	C	D	E	F	G	H	I	J	K
Line	**Description**	**Reference**	**Total Company EOY**	**Actual Cap Structure Weight (Note A)**	**Low Hypothetical Equity (Note A)**	**High Hypothetical Equity (Note A)**	**Applied Cap Structure (Note B)**	**Interest Expense**	**Cost of Capital (Note C)**	**Weighted Rate of Return (Note D)**
1	Return Based on Defined ROE									
2	Total Long Term Debt	Worksheet F, Lines 66 and 69, Col F and Line 42, Col F	$ -	#DIV/0!	64.76%	31.14 %	#DIV/0!	$ -	#DIV/0!	#DIV/0!
3	Notes Payable (Note E)	Worksheet F, Line 68, Col F; Worksheet F Line 44 Col F if balance is >0	$ -	#DIV/0!	0.00%	0.00%	#DIV/0!	$ -	0.00%	#DIV/0!
4	Total Margins and Equities	Worksheet F, Line 65, Col F	$ -	#DIV/0!	35.24%	68.86 %	#DIV/0!	N/A	9.30%	#DIV/0!
5	Total Capitalization	Subtotal	$ -	#DIV/0!	100.00%	100.00 %	#DIV/0!	$ -		#DIV/0!
6	Rate Base	Worksheet A, Line 64, Col I								#DIV/0!
7	Return on Rate Base	Line 5 * Line 6								#DIV/0!

8 Notes:

9 A.) The capital structure listed in Column (E) is calculated based on total capitalization amounts listed in Column (D). The capital structures listed Columns (F) and (G) are fixed and cannot be modified or deleted absent authorization from FERC via a Section 205 or 206 filing.

10 B.) In the case where Tri-State's actual capital structure (Column (E)) contains a Total Margins and Equities percentage between 35.24 percent and 68.86 percent, Column (H) should be populated with the actual capital structure. In the case where Tri-State's actual Margins and Equities percentage is below 35.24 percent, Column (H) should be populated with the the capital structure listed in Column (F). In the case where Tri-State's actual Margins and Equities percentage is above 68.86 percent, Column (H) should be populated with the capital structure listed in Column (G).

11 C.) The Cost of Capital for Total Margins and Equities (ROE) is fixed and cannot be modified or deleted absent authorization from FERC via a Section 205 or 206 filing. The Cost of Capital for Long Term Debt and Notes Payable is calculated by dividing the interest expense in Column (I) the total amount in Column (D).

12 D.) Column (K) values for lines 2-4 equal Column (H) values multiplied by Column (J) values.

13 E.) Only populate if the balance is greater than zero.

14 F.) RUSFOR, Part A, Sect A, L24b for long term debt and RUSFOR, Part A, Sect A, L26b for notes payable.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Load

Data:

A	B	C	D	E
Line	**Description**	**Total CP Load**	**Adjustments**	**Network Demand (KW) - West**
1	January	-		-
2	February	-		-
3	March	-		-
4	April	-		-
5	May	-		-
6	June	-		-
7	July	-		-
8	August	-		-
9	September	-		-
10	October	-		-
11	November	-		-
12	December	-		-
13	Total (kW-Mo)	0	-	-
14	Average (kW-Mo)	-	-	-

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Allocation Factors

Data:

A Line	B Description	C Reference	D Total	E Allocation Factor	F Allocation	G Allocated
1	Production Wages & Salaries	Worksheet K, Line 2, Col F	-	Direct Zero	0.000%	$ -
2	Transmission Wages & Salaries	Worksheet K, Line 3, Col F Less Line 14, Col F	-	T-Tran Plant	#DIV/0!	#DIV/0!
3	561 Load Dispatch Salaries	Worksheet K, Line 14, Col F	-	Direct Zero	0.000%	$ -
4	Distribution Wages & Salaries	Worksheet K, Line 4, Col F	-	Direct Zero	0.000%	$ -
5	Customer Accounting	Worksheet K, Line 5, Col F	-	T-Tran Plant	#DIV/0!	#DIV/0!
6	Customer Service	Worksheet K, Line 6, Col F	-	Direct Zero	0.000%	$ -
7	Customer Sales	Worksheet K, Line 7, Col F	-	Direct Zero	0.000%	$ -
8		Sum	$ -			#DIV/0!
9	**T-Wage Allocation**					**#DIV/0!**
10	352-353 Transmission Stations	Worksheet F, Sum (Lines 79 and 80), Col F and Worksheet U, Line 10, (Cols I and K)/2	$ -			$ -
11	**T-Tran Stations**					**#DIV/0!**
12	Transmission Lines	Worksheet F, Sum (Lines 78 and 81), Col F and Worksheet V, Line 10, (Cols I and K)/2	$ -			$ -
13	**T-Tran Lines**					**#DIV/0!**
14	Transmission Qualifying Plant	Lines 10 and 12 above and Worksheet A, Line 12, Col I	$ -			$ -
15	**T-Tran Plant**					**#DIV/0!**
16	Plant in Service	Worksheet A, Line 21, Col F and I	$ -			#DIV/0!
17	**T-Plant Allocation**					**#DIV/0!**
18	Net Plant in Service	Worksheet A, Line 42, Col F and I	$ -			#DIV/0!
19	**T-Net Allocation**					**#DIV/0!**
20	**Direct Zero**					**0.00%**
21	**Direct 100**					**100.00%**

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Inputs

Data:

A Line	B Description	C Reference	D BOY	E EOY	F Total
1	Billing Lag in days	Industry Standard			45
2	**Monthly Load (Total KW)**				
3	Jan	Company Records			
4	Feb	Company Records			
5	Mar	Company Records			
6	Apr	Company Records			
7	May	Company Records			
8	Jun	Company Records			
9	Jul	Company Records			
10	Aug	Company Records			
11	Sep	Company Records			
12	Oct	Company Records			
13	Nov	Company Records			
14	Dec	Company Records			
15	**RUSFOR Input**				
16	Electric Energy Revenues	RUSFOR, Part A, Section A, Line 1, Col. b			
17	Income From Leased Property	RUSFOR, Part A, Section A, Line 2, Col. b			
18	Other Operating Revenue & Income	RUSFOR, Part A, Section A, Line 3, Col. b			
19	Total Operating Revenues & Patronage Capital	Subtotal			$ -
20	**Operating Expense**				
21	Op Exp.-Production excluding fuel	RUSFOR, Part A, Section A, Line 5, Col. b			
22	Op Exp.-Production fuel	RUSFOR, Part A, Section A, Line 6, Col. b			
23	Op Exp.-Other Power Supply	RUSFOR, Part A, Section A, Line 7, Col. b			

24	Op Exp.-Transmission	RUSFOR, Part A, Section A, Line 8, Col. b		
25	Op Exp.-RTO/ISO	RUSFOR, Part A, Section A, Line 9, Col. b		
26	Op Exp.-Distribution	RUSFOR, Part A, Section A, Line 10, Col. b		
27	Op Exp.-Consumer Accounts	RUSFOR, Part A, Section A, Line 11, Col. b		
28	Op Exp.-Customer Service	RUSFOR, Part A, Section A, Line 12, Col. b		
29	Op Exp.-Sales	RUSFOR, Part A, Section A, Line 13, Col. b		
30	Op Exp.-Admin and General	RUSFOR, Part A, Section A, Line 14, Col. b		
31	Total Operation Expense	Subtotal	$ -	
32	**Maintenance Expense**			
33	Maint. Exp.-Production	RUSFOR, Part A, Section A, Line 16, Col. b		
34	Maint. Exp.-Transmission	RUSFOR, Part A, Section A, Line 17, Col. b		
35	Maint. Exp.-RTO/ISO	RUSFOR, Part A, Section A, Line 18, Col. b		
36	Maint. Exp.-Distribution	RUSFOR, Part A, Section A, Line 19, Col. b		
37	Maint. Exp.-General Plant	RUSFOR, Part A, Section A, Line 20, Col. b		
38	Total Maintenance Expense	Subtotal	$ -	
39	**Interest, Taxes and Other Deductions**			
40	Depreciation & Amortization Expense	RUSFOR, Part A, Section A, Line 22, Col. b		
41	Taxes	RUSFOR, Part A, Section A, Line 23, Col. b		
42	Interest on Long Term Debt	RUSFOR, Part A, Section A, Line 24, Col. b		
43	Interest Charged to Construction - Credit	RUSFOR, Part A, Section A, Line 25, Col. b		
44	Other Interest Expense	RUSFOR, Part A, Section A, Line 26, Col. b		
45	Asset Retirement Obligations	RUSFOR, Part A, Section A, Line 27, Col. b		
46	Other Deductions	RUSFOR, Part A, Section A, Line 28, Col. b		
47	Total Cost of Electric Service	Subtotal	$ -	
48	Operating Margins	Calculated		$ -
49	Interest Income	RUSFOR, Part A, Section A, Line 31, Col. b		
50	Allowance For Funds Used During Construction	RUSFOR, Part A, Section A, Line 32, Col. b		
51	Income (Loss) from Equity Investments	RUSFOR, Part A, Section A, Line 33, Col. b		
52	Other Non-operating Income (Net)	RUSFOR, Part A, Section A, Line 34, Col. b		
53	Generations & Transmission Capital Credits	RUSFOR, Part A, Section A, Line 35, Col. b		
54	Other Capital Credits and Patronage Dividends	RUSFOR, Part A, Section A, Line 36, Col. b		
55	Extraordinary Items	RUSFOR, Part A, Section A, Line 37, Col. b		
56	**Net Patronage Capital or Margins**	Calculated	$ -	

57	**Section B. Balance Sheet**				
58	**Assets**		BOY	EOY	Average
59	Construction Work in Progress	RUSFOR, Part A, Section B, Line 2			$ -
60	Notes Receivable (Net)	RUSFOR, Part A, Section B, Line 19			$ -
61	Prepayments *(Acct 165)*	Past Year & Current RUSFOR, Part A, Section B, Line 25			$ -
62	Other Current and Accrued Assets	Past Year & Current RUSFOR, Part A, Section B, Line 26			$ -
63	Accumulated Deferred Income Taxes *(Acct 190)*	Past Year & Current RUSFOR, Part A, Section B, Line 31			$ -
64	**Liabilities**				Total
65	Total Margins & Equities	RUSFOR, Part A, Section B, Line 39			$ -
66	Total Long Term Debt	RUSFOR, Part A, Section B, Line 43			$ -
67	Obligations Under Capital Leases - Non Current	RUSFOR, Part A, Section B, Line 44			$ -
68	Notes Payable	RUSFOR, Part A, Section B, Line 47			$ -
69	Current Maturities Long Term Debt	RUSFOR, Part A, Section B, Line 49			$ -
70	Current Maturities Long Term Debt - Rural Dev.	RUSFOR, Part A, Section B, Line 50			$ -
71	Accumulated Deferred Income Taxes *(Acct 283)*	RUSFOR, Part A, Section B, Line 57			$ -
			BOY	EOY	Average
72	301-303 Total Intangible Plant	Past Year & Current RUSFOR, Part H, Sect A, Line 1			$ -
					-
73	310 Steam Plant	Past Year & Current RUSFOR, Part H, Section A, Line 2			$ -
74	320 Nuclear Plant	Past Year & Current RUSFOR, Part H, Section A, Line 3			$ -
75	330 Hydro Plant	Past Year & Current RUSFOR, Part H, Section A, Line 4			$ -
76	340 Other Prod Plant	Past Year & Current RUSFOR, Part H, Section A, Line 5			$ -
77	**Total Production Plant**	Subtotal	$ -	$ -	-
					-
78	350 Land & Land Rights	Past Year & Current RUSFOR, Part H, Section A, Line 7			$ -
79	352 Structures and Improvements	Past Year & Current RUSFOR, Part H, Section A, Line 8			$ -
80	353 Station Equipment	Past Year & Current RUSFOR, Part H, Section A, Line 9			$ -
81	354 thru 359.1 Other Transmission Plant	Past Year & Current RUSFOR, Part H, Section A, Line 10			$ -
82	**Total Transmission Plant**	Subtotal	$ -	$ -	0
83	360 Land and Land Rights	Past Year & Current RUSFOR, Part H, Section A, Line 12			$ -
84	361 Structures and Improvements	Past Year & Current RUSFOR, Part H, Section A, Line 13			$ -
85	362 Station Equipment	Past Year & Current RUSFOR, Part H, Section A, Line 14			$ -
86	363-374 Other Distribution Plant	Past Year & Current RUSFOR,			$

		Part H, Section A, Line 15			-
87	**Total Distribution Plant**	Subtotal	$ -	$ -	$ -
88	380-386 RTO/ISO Plant	Past Year & Current RUSFOR, Part H, Section A, Line 17			$ -
89	389 thru 399.1 Total General Plant	Past Year & Current RUSFOR, Part H, Section A, Line 18			$ -
90	**Electric Plant In Service**	Subtotal	$ -	$ -	0
91	102 Electric Plant Purchased or Sold	Past Year & Current RUSFOR, Part H, Section A, Line 20			$ -
92	104 Electric Plant Leased to Others	Past Year & Current RUSFOR, Part H, Section A, Line 21			$ -
93	105 Electric Plant Held For Future Use	Past Year & Current RUSFOR, Part H, Section A, Line 22			$ -
94	106 Completed Construction Not Classified	Past Year & Current RUSFOR, Part H, Section A, Line 23			$ -
95	114 Acquisition Adjustment	Past Year & Current RUSFOR, Part H, Section A, Line 24			$ -
96	118 Other Utility Plant	Past Year & Current RUSFOR, Part H, Section A, Line 25			$ -
97	120 Nuclear Fuel Assemblies	Past Year & Current RUSFOR, Part H, Section A, Line 26			$ -
98	107 Construction Work in Progress	Past Year & Current RUSFOR, Part H, Section A, Line 28			$ -
99	**Total Utility Plant**	Subtotal	$ -	$ -	0
100	Depreciation and Amortization Reserves		BOY	EOY	Average
101	108.1 Depr Rsv. of Steam Plant	Past Year & Current RUSFOR, Part H, Section B, Line 1			$ -
102	108.2 Depr Rsv. of Nuclear Plant	Past Year & Current RUSFOR, Part H, Section B, Line 2			$ -
103	108.3 Depr Rsv. of Hydraulic Plant	Past Year & Current RUSFOR, Part H, Section B, Line 3			$ -
104	108.4 Depr Rsv. of Other Prod Plant	Past Year & Current RUSFOR, Part H, Section B, Line 4			$ -
105	108.5 Depreciation of Transmission Plant	Past Year & Current RUSFOR, Part H, Section B, Line 5			$ -
106	108.6 Depreciation of Distribution Plant	Past Year & Current RUSFOR, Part H, Section B, Line 6			$ -
107	108.7 Depreciation of General Plant	Past Year & Current RUSFOR, Part H, Section B, Line 7			$ -
108	108.8 Retirement Work in Progress	Past Year & Current RUSFOR, Part H, Section B, Line 8			$ -
109	111 Amort. of Electric Plant in Service	Past Year & Current RUSFOR, Part H, Section B, Line 12			$ -
110	115 Amort. of Acquisition Adj.	Past Year & Current RUSFOR, Part H, Section B, Line 15			$ -
111	**Total Depr Reserves for Electric Plant**	Subtotal	$ -	$ -	0
					-
112	Materials and Supplies		BOY	EOY	Average
113	M&S Coal	Past Year & Current RUSFOR, Part H, Section G, Line 1			$ -
114	M&S Other Fuel	Past Year & Current RUSFOR, Part H, Section G, Line 2			$ -
115	M&S Production Plant Parts	Past Year & Current RUSFOR, Part H, Section G, Line 3			$ -
116	M&S Station Transformers & Equipment	Past Year & Current RUSFOR, Part H, Section G, Line 4			$ -

117	M&S Line Materials & Supplies	Past Year & Current RUSFOR, Part H, Section G, Line 5			$ -
118	M&S Other	Past Year & Current RUSFOR, Part H, Section G, Line 6			$ -
119	Materials and Supplies	Subtotal	$ -	$ -	-
120	<u>Depreciation Expense</u>				<u>Total</u>
121	40360 Depreciation Expense - General Plant	Trial Balance			
122	40361 Depreciation Expense - EMS Equipment (Depreciation Accounts for 390 391 393 - 399)	Trial Balance			
123	40369 Depreciation Expense - General Plant Southern	Trial Balance			
124	40370 Depreciation Expense - Sedans, Compact Utility Vehicles, Compact Pick-ups	Trial Balance			
125	40371 Depreciation Expense - Vans and Wagons	Trial Balance			
126	40372 Depreciation Expense - Full-Size Pickups, Vans, Utility Vehicles	Trial Balance			
127	40373 Depreciation Expense - Bucket Trucks, Diggers	Trial Balance			
128	40374 Depreciation Expense - Company Aircraft	Trial Balance			
129	40375 Depreciation Expense - Small Heavy Trucks	Trial Balance			
130	40376 Depreciation Expense - Medium Trucks, Flatbeds, Knuckle Booms, Etc.	Trial Balance			
131	40377 Depreciation Expense - Snowcats	Trial Balance			
132	40378 Depreciation Expense - Equipment (Dozers, Backhoes, etc.)	Trial Balance			
133	40388 Depreciation Expense - AROs	Trial Balance			
134	40398 Depreciation Expense - AROs	Trial Balance			
135	General Plant Depreciation Expense	Subtotal			$ -
136	40400 Amortization - Franchises and Consents (Amortization Account for 302)	Trial Balance			
137	40409 Amortization of Lmtd Term Electric Plant Southern Franchises	Trial Balance			
138	40500 Amortization of Other Electric Plant (Amortization Account for Deferred Debit Accounts)	Trial Balance			
139	40509 Amortization of Other Electric Plant Southern	Trial Balance			
140	40510 Amortization Miscellaneous Intangible Generation	Trial Balance			
141	40530 Amortization-Miscellaneous Intangible Lines	Trial Balance			
142	40540 Amortization-Miscellaneous Intangible Substations	Trial Balance			
143	40600 Amortization of Electric Plant Acquisition Adjustments (Amortization Account for 114 301)	Trial Balance			
144	40609 Amortization of Electric Plant Acquisition Adjust. Southern	Trial Balance			
145	40700 Amortization of Property Losses Rollup	Trial Balance			
146	Amortization of Property	Subtotal			$ -
	<u>General and Intangible Plant Inputs</u>		BOY	EOY	<u>Average</u>
147	390 - Structures and Improvements	Trial Balance			$ -
148	391.1 - Personal Computers	Company Records			$ -

149	391.11 - Furniture	Company Records	$ -
150	391.12 - Office Equipment	Company Records	$ -
151	391.13 - Computer Hardware	Company Records	$ -
152	391.14 - LRS Office Equipment	Company Records	$ -
153	391.15 - EMS Office Equipment	Company Records	$ -
154	391.16 - EMS Computer Equipment	Company Records	$ -
155	391.17 - CO41 OWNED AT JMS	Company Records	$ -
156	391.18 - SOFTWARE	Company Records	$ -
157	391.19 - Plains Furniture and Equipment	Company Records	$ -
158	392.1 - Transportation Equipment	Company Records	$ -
159	392.11 - Airplane	Company Records	$ -
160	392.12 - Snow Cats/Trailers	Company Records	$ -
161	392.13 - LRSVehicles	Company Records	$ -
162	392.14 - Plains Transportation Equipment	Company Records	$ -
163	392.15 - Diesel Trucks	Company Records	$ -
164	392.16 - Craig- Fuel Vehicles	Company Records	$ -
165	392.17 - Craig- Maintenance Vehicles	Company Records	$ -
166	392.18 - Craig- Operating Vehicles	Company Records	$ -
167	392.19 - Pickups	Company Records	$ -
168	392.2 - Autos	Company Records	$ -
169	392.21 - Heavy Duty Trucks	Company Records	$ -
170	393 - Stores Equipment	Trial Balance	$ -
171	394 - Tools, Shop and Garage Equipment	Trial Balance	$ -
172	395 - Lab & Testing Equipment	Trial Balance	$ -
173	396 - Power Operated Equipment	Trial Balance	$ -
174	397 - Communications Equipment	Trial Balance	$ -
175	398 - Miscellaneous	Trial Balance	$ -
176	303 - Miscellaneous Intangible	Trial Balance	$ -

Tri-State Generation and Transmission Association, Inc.

October 1, 2019OATT RATES FOR TRANSMISSION SERVICE

O&M

Data:

A	B	C	D	E	F
	Expenses and Costs				
Line	**Item**	**Account Name**	**Lines (a)**	**Stations (b)**	**Total**
	Transmissions Operations				
1	Supervision and Engineering	560			$ -
2	Load Dispatching	561			$ -
3	Station Expenses	562			$ -
4	Overhead Line Expenses	563			$ -
5	Underground Line Expenses	564			$ -
6	Miscellaneous Expenses	566			$ -
7	**Subtotal (1 thru 6)**		**$ -**	**$ -**	$ -
8	Transmission of Electricity by others	565			$ -
9	Rents	567			$ -
10	**Total Transmission Operations (7 thru 9)**		**$ -**	**$ -**	$ -
	Transmission Maintenance				
11	Supervision and Engineering	568			$ -
12	Structures	569			0
13	Station Equipment	570			$ -
14	Overhead Lines	571			$ -
15	Underground Lines	572			0
16	Miscellaneous Transmission Plant	573			$ -
17	**Total Transmission Maintenance (11 thru 16)**		**$ -**	**$ -**	$ -
18	**Total Transmission Expense (10+17)**		**$ -**	**$ -**	$ -
19	RTO/ISO Expense - Operation	575.1-575.8			$ -
20	RTO/ISO Expense - Maintenance	576.1-576.5			$ -
21	**Total RTO/ISO Expense (19+20)**		**$ -**	**$ -**	$ -

22	Distribution Expense - Operation	580-589			$ -
23	Distribution Expense - Maintenance	590-598			$ -
24	**Total Distribution Expense (22+23)**		**-**	**$ -**	$ -
25	**Total Operation and Maintenance (18+21+24)**		**$ -**	**$ -**	$ -
	Fixed Costs				
26	Depreciation - Transmission	403.5			$ -
27	Depreciation - Distribution	403.6			$ -
28	Interest - Transmission	427.0			$ -
29	Interest - Distribution	427.0			$ -
30	**Total Transmission (18+26+28)**		**$ -**	**$ -**	$ -
31	**Total Distribution (24+27+29)**		**-**	**$ -**	$ -
32	**Total Lines and Stations (21+30+31)**		**$ -**	**$ -**	$ -

33 Notes:

34 A.) Source: RUSFOR, Part I.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Network Credits

Data:

A	B	C	D	E	F	G
Line	**Account (A)**	**Account Description**	**BOY**	**EOY**	**Average**	**West**
1						
2						
3						
4		Total Account 252	$ -	$ -	$ -	0
5	Notes:					
6	A.) Source: Trial Balance.					
7	B.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.					

Tri-State Generation & Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Depreciation Rates

Data:

A Line	B Account No.	C Description	D Depreciation/Amortization Rate
1		**Intangible Plant**	
2	303.0	Miscellaneous Intangible	2.75%
3		**Transmission Plant**	
4	352	Structures & Improvements	2.05%
5	353	Station Equipment	1.69%
6	354	Towers and Fixtures	1.32%
7	355	Poles & Fixtures	1.88%
8	356	O/H Conductor & Devices	1.73%
9	357	Underground Conduit	1.66%
10	358	Underground Cables	2.09%
11	359	Roads and Trails	1.11%
12		**Distribution Plant**	
13	361	Distribution Plant Structures	1.52%
14	362	Distribution Plant Station Equipment	1.38%
15		**General Plant**	
16	390	Structures and Improvements	1.46%
17	391	**OFFICE FURNITURE EQUIPMENT**	
18	391.1	Personal Computers	9.53%
19	391.11	Furniture	9.53%
20	391.12	Office Equipment	9.53%
21	391.13	Computer Hardware	9.53%
22	391.14	LRS Office Equipment	9.53%
23	391.15	EMS Office Equipment	9.53%
24	391.16	EMS Computer Equipment	9.53%
25	391.17	CO41 OWNED AT JMS	9.53%
26	391.18	SOFTWARE	9.53%
27	391.19	Plains Furniture and Equipment	9.53%
28	392	**TRANSPORTATION EQUIPMENT**	
29	392.1	Transportation Equipment	2.93%
30	392.11	Airplane	2.93%
31	392.12	Snow Cats/Trailers	2.93%
32	392.13	LRSVehicles	2.93%

33	392.14	Plains Transportation Equipment	2.93%
34	392.15	Diesel Trucks	2.93%
35	392.16	Craig- Fuel Vehicles	2.93%
36	392.17	Craig- Maintenance Vehicles	2.93%
37	392.18	Craig- Operating Vehicles	2.93%
38	392.19	Pickups	2.93%
39	392.2	Autos	2.93%
40	392.21	Heavy Duty Trucks	2.93%
41	393	Stores Equipment	3.17%
42	394	Tools, Shop and Garage Equipment	2.35%
43	395	Lab & Testing Equipment	4.67%
44	396	Power Operated Equipment	2.29%
45	397	Communications Equipment	4.53%
46	398	Miscellaneous	5.94%

47 Notes:

48 A.) These rates are fixed and cannot be changed absent authorization from FERC via a Section 205 or 206 filing.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Reconciliation Adjustments
to ATRR

Data:

Reconciliation Adjustments To ATRR

A	B	C	D	E	F	G	H	I	J
Line	**ERROR IDENTIFICATION**	**Formula Reference**	**Rate Year (Note A)**	**Incorrect Amount**	**Correct Amount**	**Difference (Cred) / Chg**	**Impact on ATRR (Cred) /Chg**	**Calculated Interest (Note B)**	**Total Adjustment to ATRR**
1								$ -	$ -
2									0
3									0
4									0
5									0
6	**Total Adjustment to Gross ATRR:**								$ -

<u>Other Reconciliation Adjustments To ATRR</u>

<u>Line</u>	**ERROR IDENTIFICATION**	**Formula**	**Rate Year**	**Incorrect**	**Correct Amoun**	**Difference**	**Impact on**	**Calculated**	**Total Adjustment to ATRR**

		Reference	(Note A)	Amount	t	(Cred) / Chg	ATRR (Cred) /Chg	Interest (Note B)	
7									0
8									0
9									0
10									0
11									0
12	**Total Adjustment to ATRR:**								0

13 **Interest calculation for Item #1**

14	Quarter	Service Month	FERC Monthly Interest Rate	Monthly Interest	Monthly Over/Under Collections & Amortization (1/12 of Annual True Up Amount) (Note C)	Total Balance (quarterly compounding)	Total Balance Prior Month Col G + Current Month Col D + Col E
15	A	B	C	D = C x F	E	F	G
16				$ -	$ -	$ -	$ -
17				$ -	$ -	$ -	$ -
18				$ -	$ -	$ -	$ -
19	*			$ -	$ -	$ -	$ -
20				$ -	$ -	$ -	$ -
21				$ -	$ -	$ -	$ -
22	*			$ -	$ -	$ -	$ -
23				$ -	$ -	$ -	$ -
24				$	$	$	$

			-	-	-	-
25	*		$ -	$ -	$ -	$ -
26			$ -	$ -	$ -	$ -
27			$ -	$ -	$ -	$ -
28		Total Interest	$ -			
29		Total True-up Amount	$ -			
30	*	Total True Up Amount with Interest	$ -			
31	**Interest calculation for Item #2…**					
32	(Repeat interest calculation for other items as necessary.)					
33	<u>Notes:</u>					
34	A.) Rate Year in which the error occurred and affected the ATRR and rates paid by customers.					
35	B.) Each ATRR adjustment shall include interest based on Section 35.19a of the Commission Regulations.					
36	C.) Interest Note: The example interest calculation may need to be modified to recognize the implementation partial year.					
37	D.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.					

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Wages

Data:

A Line	B Function	C Direct Labor	D Sick, Vacation, Option, Holiday	E Benefits	F Total Labor Expense
1	**Expenses**				
2	Production				$ -
3	Transmission				$ -
4	Distribution				$ -
5	Customer Accounting				$ -
6	Customer Service				$ -
7	Customer Sales				$ -
8	Total	$ -	$ -	$ -	$ -
9		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
10	**Transmission O&M - Acct 561 - Load Dispatch**				
11	561.00 Operations				$ -
12	561.20 Transmission				$ -
13	561.25 South Trans				$ -
14	Total	$ -	$ -	$ -	$ -
15	Notes:				
16	A.) Source: Company Records				

Tri-State Generation & Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE

Annual Depreciation Expense

Data:

A Line	B Account	C Description	D BOY Amount	E EOY Amount	F Transmission Amount (Avg)	G Depreciation Rate	H Depreciation Expense
1		**Transmission Plant**					
2	350	Land and Land Rights	$0	$0	$0.00	N/A	
3	352	Structures & Improvements	$0	$0	$0	2.05%	$0
4	353	Station Equipment	$0	$0	$0	1.69%	$0
5	354	Towers and Fixtures	$0	$0	$0	1.32%	$0
6	355	Poles & Fixtures	$0	$0	$0	1.88%	$0
7	356	O/H Conductor & Devices	$0	$0	$0	1.73%	$0
8	357	Underground Conduit	$0	$0	$0	1.66%	$0
9	358	Underground Cables	$0	$0	$0	2.09%	$0
10	359	Roads and Trails	$0	$0	$0.00	1.11%	$0
11		Total Transmission Depreciation Expense	$0	$0	$0	**1.69%**	$0

A Line	B Account	C Description	D Total Company BOY Amount	E Total Company EOY Amount	F Total Company Amount (Avg)	G T-Wage Allocation Factor	H West Amount	I Depreciation Rate	J Depreciation Expense
12		**General Plant**							
13	390	Structures and Improvements	$0	$0	$0.00	#DIV/0!	#DIV/0!	1.46%	#DIV/0!
14	391.1	Personal Computers	$0	$0	$0.00	#DIV/0!	#DIV/0!	9.53%	#DIV/0!
15	391.11	Furniture	$0	$0	$0.00	#DIV/0!	#DIV/0!	9.53%	#DIV/0!
16	391.12	Office Equipment	$0	$0	$0.00	#DIV/0!	#DIV/0!	9.53%	#DIV/0!
17	391.13	Computer Hardware	$0	$0	$0.00	#DIV/0!	#DIV/0!	9.53%	#DIV/0!
18	391.14	LRS Office Equipment	$0	$0	$0.00	#DIV/0!	#DIV/0!	9.53%	#DIV/0!
19	391.15	EMS Office Equipment	$0	$0	$0.00	#DIV/0!	#DIV/0!	9.53%	#DIV/0!
20	391.16	EMS Computer Equipment	$0	$0	$0.00	#DIV/0!	#DIV/0!	9.53%	#DIV/0!
21	391.17	CO41 OWNED AT JMS	$0	$0	$0	#DIV/0!	#DIV/0!	9.53%	#DIV/0!
22	391.18	SOFTWARE	$0	$0	$0	#DIV/0!	#DIV/0!	9.53%	#DIV/0!

23	391.19	Plains Furniture and Equipment	$0	$0	$0	#DIV/0!	#DIV/0!	9.53%	#DIV/0!
24	392.1	Transportation Equipment	$0	$0	$0	#DIV/0!	#DIV/0!	2.93%	#DIV/0!
25	392.11	Airplane	$0	$0	$0	#DIV/0!	#DIV/0!	2.93%	#DIV/0!
26	392.12	Snow Cats/Trailers	$0	$0	$0	#DIV/0!	#DIV/0!	2.93%	#DIV/0!
27	392.13	LRSVehicles	$0	$0	$0	#DIV/0!	#DIV/0!	2.93%	#DIV/0!
28	392.14	Plains Transportation Equipment	$0	$0	$0	#DIV/0!	#DIV/0!	2.93%	#DIV/0!
29	392.15	Diesel Trucks	$0	$0	$0	#DIV/0!	#DIV/0!	2.93%	#DIV/0!
30	392.16	Craig- Fuel Vehicles	$0	$0	$0	#DIV/0!	#DIV/0!	2.93%	#DIV/0!
31	392.17	Craig- Maintenance Vehicles	$0	$0	$0	#DIV/0!	#DIV/0!	2.93%	#DIV/0!
32	392.18	Craig- Operating Vehicles	$0	$0	$0	#DIV/0!	#DIV/0!	2.93%	#DIV/0!
33	392.19	Pickups	$0	$0	$0	#DIV/0!	#DIV/0!	2.93%	#DIV/0!
34	392.2	Autos	$0	$0	$0	#DIV/0!	#DIV/0!	2.93%	#DIV/0!
35	392.21	Heavy Duty Trucks	$0	$0	$0	#DIV/0!	#DIV/0!	2.93%	#DIV/0!
36	393	Stores Equipment	$0	$0	$0	#DIV/0!	#DIV/0!	3.17%	#DIV/0!
37	394	Tools, Shop and Garage Equipment	$0	$0	$0	#DIV/0!	#DIV/0!	2.35%	#DIV/0!
38	395	Lab & Testing Equipment	$0	$0	$0	#DIV/0!	#DIV/0!	4.67%	#DIV/0!
39	396	Power Operated Equipment	$0	$0	$0	#DIV/0!	#DIV/0!	2.29%	#DIV/0!
40	397	Communications Equipment	$0	$0	$0	#DIV/0!	#DIV/0!	4.53%	#DIV/0!
41	398	Miscellaneous	$0	$0	$0	#DIV/0!	#DIV/0!	5.94%	#DIV/0!
42		Total General Depreciation Expense	$0	$0	$0		#DIV/0!		#DIV/0!
43		**Intangible Plant**							
44	303.0	Miscellaneous Intangible	$0	$0	$0.00	#DIV/0!	#DIV/0!	2.75%	#DIV/0!
45		Total Intangible Amortization Expense	$0	$0	$0		#DIV/0!		#DIV/0!

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE
Other Revenue

Data:

A Line	B Account	C Description	D Total Company	E East ATRR	F West ATRR	G Other
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21		Total Other Operating Revenue and Income	$ -	$ -	$ -	0
22						
23		**Summary:**	**Total**	**East**	**West**	**Other**
24	454	RENT FROM ELECTRIC PROPERTY	$ -	$ -	$ -	$ -
25	456	OTHER ELECTRIC REVENUE - ADMINISTRATIVE FEE - TSR	$ -		$ -	$ -
26	456	REVENUES FROM TRANSMISSION OF ELECTRICITY OF OTHERS INCLUDING -ST FIRM & NON-FIRM	$ -	$ -	$ -	$ -
27	456	OTHER ELECTRIC REVENUE - GFAs	$ -	$ -	$ -	$ -
28	456	OTHER ELECTRIC REVENUE	$ -	$ -	$ -	$ -
29		OTHER REVENUES	$ -	$ -	$ -	$ -
30	Notes:					

31	A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Tri-State Generation and Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE

Plant Held for Future Use

Data:

				BOY Investment			EOY Investment			Average Investment		
A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**
Line	**Facility No.**	**Asset No.**	**Description**	**Total**	**West**	**East**	**Total**	**West**	**East**	**Total**	**West**	**East**
1					$ -			$ -	$ -	$ -	$ -	$ -
2					$ -			$ -	$ -	$ -	$ -	$ -
3					$ -			$ -	$ -	$ -	$ -	$ -
4					$ -			$ -	$ -	$ -	$ -	
5					$ -			$ -	$ -	$ -	$ -	$ -
6					$ -			$ -	$ -	$ -	$ -	$ -
7					$ -			$ -	$ -	$ -	$ -	$ -
8					$ -			$ -	$ -	$ -	$ -	$ -
9					$ -			$ -	$ -	$ -	$ -	$ -
10					$ -			$ -	$ -	$ -	$ -	$ -
11					$ -			$ -	$ -	$ -	$ -	$ -
12					$ -			$ -	$ -	$ -	$ -	$ -
13					$ -			$ -	$ -	$ -	$ -	$ -
14					$ -			$ -	$ -	$ -	$ -	$ -
15					$ -			$ -	$ -	$ -	$ -	$ -
16			Subtotal Transmission Future Use Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17			Distribution Future Use Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18			General Plant Future Use Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

19	Intangible Plant Future Use Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Total Plant Held for Future Use	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

21 Notes:

22 A.) Source: Company Records

23 B.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Account 565 - Transmission of Electricity by Others

Data:

A	B	C	D	E	F
Line	**Account (A)**	**Account Description**	**Total Company**	**East**	**West**
1					
2					
3					
4					
5					
6					
7		Total Account 565	**$ -**	**$ -**	**0**
8	Notes:				

9 A.) Source: Company Records.
10 B.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Tri-State Generation & Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Account 575/576 Expenses

Data:

A Line	B Account No.	C Description	D Annual Expense Amount	E % Included in West	F West Amount
	575.1-575.8 RTO/ISO Expense - Operation				
1a					-
1b					-
…					-
2	**Total 575.1-575.8 RTO/ISO Expense - Operation (sum lines 1a-1xx) (Note A)**		-		-
	576.1-576.5 RTO/ISO Expense - Maintenance				
3a					-
3b					-
…					-
4	**576.1-576.5 RTO/ISO Expense - Maintenance (sum lines 3a-3xx) (Note B)**		-		-

5 Notes:

6 A.) The total on line 2, column D must reconcile to the amounts shown on RUSFOR.

7 B.) The total on line 4, column D must reconcile to the amounts shown on RUSFOR.

8 C.) Amounts listed on lines 1a-1xx and 3a-3xx are only eligible for inclusion in ATRR following a change in accounting procedures to the RUS Form 12 or Uniform System of Accounts, which would classify amounts in these accounts as eligible for transmission rate recovery. To the extent that this occurs, Tri-State may file a single-issue Section 205 filing with the Commission to seek recovery of these amounts in rates. Tri-State may not include any costs absent authorization from FERC via a Section 205 or 206 filing.

9 D.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Completed Construction Not Classified

Data:

A	B	C	D	E	F	G	H	I	J
Line	Fac ID	Facility Name	BOY Balance	EOY Balance	100% West	0% West	West Portion if Less than 100%	Amount	Comments
1				Completed Not Classified Total:				$0	
2								$ -	
3								$ -	
4								$ -	
5								$ -	
6								$ -	
7								$ -	
8								$ -	
9								$ -	
10								$ -	
11								$ -	
12								$ -	
13								$ -	
14								$ -	
15								$ -	
16								$ -	
17								$ -	
18								$ -	
19								$ -	
20								$ -	
21								$ -	
22								$	

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23	$ -
24	$ -
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28	$ -
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241		$ -
242		$ -
243		$ -
244		$ -
245		$ -
246		$ -
247		$ -
248		$ -
249		$ -
250		$ -
251	Notes:	
252	A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.	

Tri-State Generation and Transmission Association, Inc.
OATT RATES FOR
TRANSMISSION SERVICE

Construction Work in Progress

Data:

A	B	C	D	E	F	G	H	I	J	K
Line	**Facility Name**	**Allowable Recovery (Note A)**	**Pricing Zone (Note B)**	**Fac ID**	**Construction Start Date**	**In-Service Date (Estimated)**	**BOY Balance**	**EOY Balance**	**Average Balance (Col H & I)**	**Includable in Rate Base (Note C) (Col C * Col J)**
1									**Construction Work in Progress Total:**	**#DIV/0!**
2		0.5							#DIV/0!	#DIV/0!
3		0.5							#DIV/0!	#DIV/0!
4		0.5							#DIV/0!	#DIV/0!
5		0.5							#DIV/0!	#DIV/0!
6		0.5							#DIV/0!	#DIV/0!
7		0.5							#DIV/0!	#DIV/0!
8		0.5							#DIV/0!	#DIV/0!
9		0.5							#DIV/0!	#DIV/0!
10		0.5							#DIV/0!	#DIV/0!
11		0.5							#DIV/0!	#DIV/0!
12		0.5							#DIV/0!	#DIV/0!
13		0.5							#DIV/0!	#DIV/0!
14		0.5							#DIV/0!	#DIV/0!
15		0.5							#DIV/0!	#DIV/0!
16		0.5							#DIV/0!	#DIV/0!
17		0.5							#DIV/0!	#DIV/0!
18		0.5							#DIV/0!	#DIV/0!
19		0.5							#DIV/0!	#DIV/0!
20		0.5							#DIV/0!	#DIV/0!
21		0.5							#DIV/	#DIV/0!

		0!	
22	0.5	#DIV/0!	#DIV/0!
23	0.5	#DIV/0!	#DIV/0!
24	0.5	#DIV/0!	#DIV/0!
25	0.5	#DIV/0!	#DIV/0!
26	0.5	#DIV/0!	#DIV/0!
27	0.5	#DIV/0!	#DIV/0!
28	0.5	#DIV/0!	#DIV/0!
29	0.5	#DIV/0!	#DIV/0!
30	0.5	#DIV/0!	#DIV/0!
31	0.5	#DIV/0!	#DIV/0!
32	0.5	#DIV/0!	#DIV/0!
33	0.5	#DIV/0!	#DIV/0!
34	0.5	#DIV/0!	#DIV/0!
35	0.5	#DIV/0!	#DIV/0!
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242 Notes:

243 A.) Percentage recovery cannot be added or changed absent approval from FERC.

244 B.) CWIP amounts should be directly assigned to pricing zones in Column E.

245 C.) AFUDC ceases when CWIP is recovered in rate base. No CWIP will be included in rate base absent FERC authorization. Accounting procedures must be provided during the annual update to ensure that there is no duplicate recovery of CWIP and corresponding AFUDC capitalized.

246 D.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Tri-State Generation and Transmission Association, Inc.

OATT RATES FOR TRANSMISSION SERVICE

Regulatory and Commission Expenses

Data:

A	B	C	D	E	F	G
Line	**Account 928**	**Description**	**Total Company**	**East-Expenses**	**West Expenses**	**Other Expenses**
1						
2						
3						
4		Total	$ -	$ -	$ -	$ -

5 Notes:
6

A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Tri-State Generation and Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE

Retirement Work in Progress

Data:

A	B	C	D	E	F	G	H	I	J
Line	Fac ID	Facility	BOY Balance	EOY Balance	Average Balance	100% West	0% West	West Portion if Less than 100%	Amount
1						Retirement Work in Progress Total:			$ -
2					$ -				$ -
3					$ -				$ -
4					$ -				$ -
5					$ -				$ -
6					$ -				$ -
7					$ -				$ -
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40	Notes:		
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A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Tri-State Generation and Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE
Eligible Transmission Substations Data:

				Total Company Amount				Amount included	
A	B	C	D	E	F	G	H	I	J
Line	Account Number	Description of Asset	Type of Asset	BOY Gross Plant Cost	BOY Accumulated Depreciation	EOY Gross Plant Cost	EOY Accumulated Depreciation	BOY Gross Plant Cost	BOY Accumulated Depreciation
1	350	LAND AND LAND RIGHTS	TRANSMISSION SUBSTATION						
2	352	STRUCTURES AND IMPROVEMENTS	TRANSMISSION SUBSTATION						
3	353	STATION EQUIPMENT	TRANSMISSION SUBSTATION						
4	354	TOWER AND FIXTURES	TRANSMISSION SUBSTATION						
5	355	POLES AND FIXTURES	TRANSMISSION SUBSTATION						
6	356	OVERHEAD CONDUCTORS AND DEVICES	TRANSMISSION SUBSTATION						
7	357	UNDERGROUND CONDUIT	TRANSMISSION SUBSTATION						
8	358	UNDERGROUND CONDUCTOR AND DEVICES	TRANSMISSION SUBSTATION						
9	359	ROADS AND TRAILS	TRANSMISSION SUBSTATION						
10	**Totals**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

11 Notes:
12 A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future
Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a F
206 filing.

Tri-State Generation and Transmission Association, Inc.
OATT RATES FOR TRANSMISSION SERVICE
Eligible Transmission Lines Data:

				Total Company Amount				Amount included in Tri-St		
A	B	C	D	E	F	G	H	I	J	K
Line	Account Number	Description of Asset	Type of Asset	BOY Gross Plant Cost	BOY Accumulated Depreciation	EOY Gross Plant Cost	EOY Accumulated Depreciation	BOY Gross Plant Cost	BOY Accumulated Depreciation	EO Gro Plant
1	350	LAND AND LAND RIGHTS	TRANSMISSION LINE							
2	352	STRUCTURES AND IMPROVEMENTS	TRANSMISSION LINE							
3	353	STATION EQUIPMENT	TRANSMISSION LINE							
4	354	TOWER AND FIXTURES	TRANSMISSION LINE							
5	355	POLES AND FIXTURES	TRANSMISSION LINE							
6	356	OVERHEAD CONDUCTORS AND DEVICES	TRANSMISSION LINE							
7	357	UNDERGROUND CONDUIT	TRANSMISSION LINE							
8	358	UNDERGROUND CONDUCTOR AND DEVICES	TRANSMISSION LINE							
9	359	ROADS AND TRAILS	TRANSMISSION LINE							
10	**Totals**			$ -	$ -	$ -	$ -	$ -	$ -	

11 Notes:

12 A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be ch Federal Power Act section 205 or 206 filing.

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, Open Access Transmission Tariff, 1.0.0, A
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Tariff Record ID: 15
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0

Proposed Date: 2019-09-21
Priority Order: 2020
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ATTACHMENT N

STANDARD LARGE GENERATOR INTERCONNECTION PROCEDURES (LGIP)

including

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT (LGIA)

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STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

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SECTION 1. DEFINITIONS

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the Regional Entity, as defined by Section 215 of the Federal Power Act, applicable to the Transmission System to which the Generating

Facility is directly interconnected.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by NERC.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which

transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider’s Transmission System, Transmission Provider’s Interconnection Facilities or the electric systems of others to which the Transmission Provider’s Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer’s Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider’s Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider’s Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a *et seq*.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party’s control. A Force Majeure

event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Generator Interconnection Agreement (GIA) shall mean Transmission Provider's Generator Interconnection Agreement prior to the effective date of the Standard Large Generator Interconnection Agreement (LGIA).

Generator Interconnection Procedures (GIP) shall mean Transmission Provider's Generator Interconnection Procedures prior to the effective date of the Standard Large Generator Interconnection Procedures (LGIP).

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of “hazardous substances,” “hazardous wastes,” “hazardous materials,” “hazardous constituents,” “restricted hazardous materials,” “extremely hazardous substances,” “toxic substances,” “radioactive substances,” “contaminants,” “pollutants,” “toxic pollutants” or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission Provider's Transmission System. The scope of the study is defined in Section 8 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 6 of the Standard Large Generator Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of

the Standard Large Generator Interconnection Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for

sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Queue Position shall mean the order of a valid Interconnection Request relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and

earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider’s Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean Tri-State Generation and Transmission Association, Inc., the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Section 2. Scope and Application

2.1 Application of Standard Large Generator Interconnection Procedures.

Sections 2 through 13 apply to processing an Interconnection Request pertaining to a Large Generating Facility.

2.2 Comparability.

Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this LGIP. Transmission Provider will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by Transmission Provider, its subsidiaries or Affiliates or others.

2.3 Base Case Data.

Transmission Provider shall provide base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list upon request subject to confidentiality provisions in LGIP Section 13.1. Transmission Provider is permitted to require that Interconnection Customer sign a confidentiality agreement before the release of commercially sensitive information or Critical Energy Infrastructure Information in the Base Case data. Such databases and lists, hereinafter referred to as Base Cases, shall include all (1) generation projects and (2) transmission projects, including merchant transmission projects that are proposed for the Transmission System for which a transmission expansion plan has been submitted and approved by the applicable authority.

2.4 No Applicability to Transmission Service.

Nothing in this LGIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

Section 3. Interconnection Requests

3.1 General.

An Interconnection Customer shall submit to the Transmission Provider an Interconnection Request in the form of Appendix 1 to this LGIP and a refundable deposit of $10,000. The Transmission Provider shall apply the deposit toward the cost of an Interconnection Feasibility Study. Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests.

At Interconnection Customer's option, Transmission Provider and Interconnection Customer will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point(s) of Interconnection to be studied no later than the execution of the Interconnection Feasibility Study Agreement.

3.2 Identification of Types of Interconnection Services.

At the time the Interconnection Request is submitted, Interconnection Customer must request either Energy Resource Interconnection Service or Network Resource Interconnection Service, as described ; provided, however, any Interconnection Customer requesting Network Resource Interconnection Service may also request that it be concurrently studied for Energy Resource Interconnection Service, up to the point when an Interconnection Facility Study Agreement is executed. Interconnection Customer may then elect to proceed with Network Resource Interconnection Service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed.

3.2.1 Energy Resource Interconnection Service.

3.2.1.1 The Product. Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility’s output using the existing firm or non-firm capacity of the Transmission System on an “as available” basis. Energy Resource Interconnection Service does not in and of itself convey any right to deliver electricity to any specific customer or Point of Delivery.

3.2.1.2 The Study. The study consists of short circuit/fault duty, steady state (thermal and voltage) and stability analyses. The short circuit/fault duty analysis would identify direct Interconnection Facilities required and the Network Upgrades necessary to address short circuit issues associated with the Interconnection Facilities. The stability and steady state studies would identify necessary

upgrades to allow full output of the proposed Large Generating Facility and would also identify the maximum allowed output, at the time the study is performed, of the interconnecting Large Generating Facility without requiring additional Network Upgrades.

3.2.2 Network Resource Interconnection Service.

3.2.2.1 **The Product**. Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service allows Interconnection Customer 's Large Generating Facility to be designated as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur.

3.2.2.2 **The Study**. The Interconnection Study for Network Resource Interconnection Service shall assure that Interconnection Customer's Large Generating Facility meets the requirements for Network Resource Interconnection Service and as a general matter, that such Large Generating Facility's interconnection is also studied with Transmission Provider’s Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Large Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on Transmission Provider’s Transmission System, consistent with Transmission Provider’s reliability criteria and procedures. This approach assumes that some portion of existing Network Resources are displaced by the output of Interconnection Customer's Large Generating Facility. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery. The Transmission Provider may also study the Transmission System under non-peak load conditions. However, upon request by the Interconnection Customer, the Transmission Provider must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

3.3 Valid Interconnection Request.

3.3.1 Initiating an Interconnection Request.

To initiate an Interconnection Request, Interconnection Customer must submit all of the following: (i) a $10,000 deposit, (ii) a completed application in the form of Appendix 1, and (iii) demonstration of Site Control or a posting of an additional deposit of $10,000. Such deposits shall be applied toward any Interconnection Studies pursuant to the Interconnection Request. If Interconnection Customer demonstrates Site Control within the cure period specified in Section 3.3.3 after submitting its Interconnection Request, the additional deposit shall be refundable; otherwise, all such deposit(s), additional and initial, become non-refundable.

The expected In-Service Date of the new Large Generating Facility or increase in capacity of the existing Generating Facility shall be no more than the process window for the regional expansion planning period (or in the absence of a regional planning process, the process window for Transmission Provider's expansion planning period) not to exceed seven years from the date the Interconnection Request is received by Transmission Provider, unless Interconnection Customer demonstrates that engineering, permitting and construction of the new Large Generating Facility or increase in capacity of the existing Generating Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by Transmission Provider by a period up to ten years, or longer where Interconnection Customer and Transmission Provider agree, such agreement not to be unreasonably withheld.

3.3.2 Acknowledgment of Interconnection Request.

Transmission Provider shall acknowledge receipt of the Interconnection Request within five (5) Business Days of receipt of the request and attach a copy of the received Interconnection Request to the acknowledgement.

3.3.3 Deficiencies in Interconnection Request.

An Interconnection Request will not be considered to be a valid request until all items in Section 3.3.1 have been received by Transmission Provider. If an Interconnection Request fails to meet the requirements set forth in Section 3.3.1, Transmission Provider shall notify Interconnection Customer within five (5) Business Days of receipt of the initial Interconnection Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request. Interconnection Customer shall provide Transmission Provider the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. Failure by Interconnection Customer to comply with this Section 3.3.3 shall be treated in accordance with Section 3.6.

3.3.4 Scoping Meeting.

Within ten (10) Business Days after receipt of a valid Interconnection Request, Transmission Provider shall establish a date agreeable to Interconnection Customer for the Scoping Meeting, and such date shall be no later than thirty (30) Calendar Days from receipt of the valid

Interconnection Request, unless otherwise mutually agreed upon by the Parties.

The purpose of the Scoping Meeting shall be to discuss alternative interconnection options, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection. Transmission Provider and Interconnection Customer will bring to the meeting such technical data, including, but not limited to: (i) general facility loadings, (ii) general instability issues, (iii) general short circuit issues, (iv) general voltage issues, and (v) general reliability issues as may be reasonably required to accomplish the purpose of the meeting. Transmission Provider and Interconnection Customer will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Interconnection Customer shall designate its Point of Interconnection, pursuant to Section 6.1, and one or more available alternative Point(s) of Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose.

3.4 OASIS Posting

Transmission Provider will maintain on its OASIS a list of all Interconnection Requests. The list will identify, for each Interconnection Request: (i) the maximum summer and winter megawatt electrical output; (ii) the location by county and state; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected In-Service Date; (v) the status of the Interconnection Request, including Queue Position; (vi) the type of Interconnection Service being requested; and (vii) the availability of any studies related to the Interconnection Request; (viii) the date of the Interconnection Request; (ix) the type of Generating Facility to be constructed (combined cycle, base load or combustion turbine and fuel type); and (x) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed. Except in the case of an Affiliate, the list will not disclose the identity of Interconnection Customer until Interconnection Customer executes an LGIA or requests that the Transmission Provider file an unexecuted LGIA with FERC. Before holding a Scoping Meeting with its Affiliate, Transmission Provider shall post on OASIS an advance notice of its intent to do so. Transmission Provider shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection Study reports shall be posted to Transmission Provider's OASIS site subsequent to the meeting between Interconnection Customer and Transmission Provider to discuss the applicable study results. Transmission Provider shall also post any known deviations in the Large Generating Facility's In-Service Date.

3.5 Coordination with Affected Systems.

Transmission Provider will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators and, if possible, include those results (if available) in its applicable Interconnection Study within the time frame specified in this LGIP. Transmission Provider will include such Affected System Operators in all meetings held with Interconnection Customer as required by this LGIP. Interconnection Customer will cooperate with the Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider which may be an Affected System shall cooperate with Transmission Provider with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

3.6 Withdrawal.

Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to Transmission Provider. In addition, if Interconnection Customer fails to adhere to all requirements of this LGIP, except as provided in Section 13.5 (Disputes), Transmission Provider shall deem the Interconnection Request to be withdrawn and shall provide written notice to Interconnection Customer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Upon receipt of such written notice, Interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify Transmission Provider of its intent to pursue Dispute Resolution.

Withdrawal shall result in the loss of Interconnection Customer’s Queue Position. If an Interconnection Customer disputes the withdrawal and loss of its Queue Position, then during Dispute Resolution, Interconnection Customer's Interconnection Request is eliminated from the queue until such time that the outcome of Dispute Resolution would restore its Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to Transmission Provider all costs that Transmission Provider prudently incurs with respect to that Interconnection Request prior to Transmission Provider’s receipt of notice described above. Interconnection Customer must pay all monies due to Transmission Provider before it is allowed to obtain any Interconnection Study data or results.

Transmission Provider shall (i) update the OASIS Queue Position posting and (ii) refund to Interconnection Customer any portion of Interconnection Customer's deposit or study payments that exceeds the costs that Transmission Provider has incurred, including interest calculated in accordance with section 35.19a(a)(2) of FERC’s regulations. In the event of such withdrawal, Transmission Provider, subject to the confidentiality provisions of Section 13.1, shall provide, at Interconnection Customer's request, all information that Transmission Provider developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

Section 4. Queue Position.

4.1 General.

Transmission Provider shall assign a Queue Position based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, and Interconnection Customer provides such information in accordance with Section 3.3.3, then Transmission Provider shall assign Interconnection Customer a Queue Position based on the date the application form was originally filed. Moving a Point of Interconnection shall result in a lowering of Queue Position if it is deemed a Material Modification under Section 4.4.3.

The Queue Position of each Interconnection Request will be used to determine the order of performing the Interconnection Studies and determination of cost responsibility for the facilities necessary to accommodate the Interconnection Request. A higher queued Interconnection Request is one that has been placed "earlier" in the queue in relation to another Interconnection Request that is lower queued.

Transmission Provider may allocate the cost of the common upgrades for clustered Interconnection Requests without regard to Queue Position.

4.2 Clustering.

At Transmission Provider's option, Interconnection Requests may be studied serially or in clusters for the purpose of the Interconnection System Impact Study.

Clustering shall be implemented on the basis of Queue Position. If Transmission Provider elects to study Interconnection Requests using Clustering, all Interconnection Requests received within a period not to exceed one hundred and eighty (180) Calendar Days, hereinafter referred to as the "Queue Cluster Window" shall be studied together without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service. The deadline for completing all Interconnection System Impact Studies for which an Interconnection System Impact Study Agreement has been executed during a Queue Cluster Window shall be in accordance with Section 7.4, for all Interconnection Requests assigned to the same Queue Cluster Window. Transmission Provider may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Large Generating Facility.

Clustering Interconnection System Impact Studies shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the Transmission System's capabilities at the time of each study.

The Queue Cluster Window shall have a fixed time interval based on fixed annual opening and closing dates. Any changes to the established Queue Cluster Window interval and opening or closing dates shall be announced with a posting on Transmission Provider's OASIS beginning at least one hundred and eighty (180) Calendar Days in advance of the change and continuing thereafter through the end date of the first Queue Cluster Window that is to be modified.

4.3 Transferability of Queue Position.
An Interconnection Customer may transfer its Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change.

4.4 Modifications.
Interconnection Customer shall submit to Transmission Provider, in writing, modifications to any information provided in the Interconnection Request. Interconnection Customer shall retain its Queue Position if the modifications are in accordance with Sections 4.4.1, 4.4.2 or 4.4.5, or are determined not to be Material Modifications pursuant to Section 4.4.3.

Notwithstanding the above, during the course of the Interconnection Studies, either Interconnection Customer or Transmission Provider may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes are acceptable to Transmission Provider and Interconnection Customer, such acceptance not to be unreasonably withheld, Transmission Provider shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 6.4, Section 7.6 and Section 8.5 as applicable and Interconnection Customer shall retain its Queue Position.

4.4.1 Prior to the return of the executed Interconnection System Impact Study Agreement to Transmission Provider, modifications permitted under this Section shall include specifically: (a) a decrease of up to 60 percent of electrical output (MW) of the proposed project; (b) modifying the technical parameters associated with the Large Generating Facility technology or the Large Generating Facility step-up transformer impedance characteristics; and (c) modifying the interconnection configuration. For plant increases, the incremental increase in plant output will go to the end of the queue for the purposes of cost allocation and study analysis.

4.4.2 Prior to the return of the executed Interconnection Facility Study Agreement to Transmission Provider, the modifications permitted under this Section shall include specifically: (a) additional 15 percent decrease of electrical output (MW), and ; (b) Large Generating Facility technical parameters associated with modifications to Large Generating Facility technology and transformer impedances; provided, however, the incremental costs associated with those modifications are the responsibility of the requesting Interconnection Customer.

4.4.3 Prior to making any modification other than those specifically permitted by Sections 4.4.1, 4.4.2, and 4.4.5, Interconnection Customer may first request that Transmission Provider evaluate whether such modification is a Material Modification. In response to Interconnection Customer's request, Transmission Provider shall evaluate the proposed modifications prior to making them and inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection, except those deemed acceptable

under Sections 4.4.1, 6.1, 7.2, or so allowed elsewhere, shall constitute a Material Modification. Interconnection Customer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

4.4.4 Upon receipt of Interconnection Customer's request for modification permitted under this Section 4.4, the Transmission Provider shall commence and perform any necessary additional studies as soon as practicable, but in no event shall the Transmission Provider commence such studies later than thirty (30) Calendar Days after receiving notice of Interconnection Customer's request. Any additional studies resulting from such modification shall be done at Interconnection Customer's cost.

4.4.5 Extensions of less than three (3) cumulative years in the Commercial Operation Date of the Large Generating Facility to which the Interconnection Request relates are not material and should be handled through construction sequencing.

Section 5. Procedures for Interconnection Requests Submitted Prior to Effective Date of Standard Large Generator Interconnection Procedures.

5.1 Queue Position for Pending Requests.

5.1.1 Any Interconnection Customer assigned a Queue Position prior to the effective date of this LGIP shall retain that Queue Position with the exceptions discussed below:

5.1.1.1 If an Interconnection Study Agreement has not been executed as of the effective date of this LGIP, then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with this LGIP.

5.1.1.2 If an Interconnection Study Agreement has been executed prior to the effective date of this LGIP, such Interconnection Study shall be completed in accordance with the terms of such agreement. With respect to any remaining studies for which an Interconnection Customer has not signed an Interconnection Study Agreement prior to the effective date of the LGIP, the Interconnection Customer must go forward with the completion of the necessary Interconnection Studies (for which it does not have a signed Interconnection Studies Agreement) in accordance with this LGIP. Interconnection Customers in deferral under the Transmission Provider’s GIP have the Transition Period (as defined in Section 5.1.2 of this LGIP) to notify the Transmission Provider of their request to come out of deferral; otherwise, the Interconnection Customers will be withdrawn from the Interconnection Study process and any remaining deposit will be refunded, as appropriate. Interconnection Customers electing to come out of deferral and electing to execute an Interconnection Facilities Study Agreement will be assigned a Queue Position for the Interconnection Facilities Study and have their Interconnection Request processed based on the order in which Transmission Provider receives the executed Interconnection Facilities Study Agreement.

5.1.1.3 If a GIA has been executed before the effective date of the LGIP, then the GIA would be grandfathered.

5.1.2 **Transition Period**. To the extent necessary, Transmission Provider and Interconnection Customers with an outstanding request (i.e., an Interconnection Request for which an LGIA has not been submitted to FERC for approval as of the effective date of this LGIP) shall transition to this LGIP within a reasonable period of time not to exceed sixty (60) Calendar Days. The use of the term "outstanding request" herein shall mean any Interconnection Request, on the effective date of this LGIP: (i) that has been submitted but not yet accepted by Transmission Provider; (ii) where the related interconnection agreement has not yet been submitted to FERC for approval in executed or unexecuted form, (iii) where the relevant Interconnection Study Agreements have not yet been executed, or (iv) where any of the relevant Interconnection Studies are in process but not yet completed. Any Interconnection Customer with an outstanding request as of the effective date of this LGIP may request a reasonable extension of any deadline, otherwise applicable, if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension shall be granted by Transmission Provider to the extent consistent with the intent and process provided for under this LGIP.

5.2 **New Transmission Provider.**

If Transmission Provider transfers control of its Transmission System to a successor Transmission Provider during the period when an Interconnection Request is pending, the original Transmission Provider shall transfer to the successor Transmission Provider any amount of the deposit or payment with interest thereon that exceeds the cost that it incurred to evaluate the request for interconnection. Any difference between such net amount and the deposit or payment required by this LGIP shall be paid by or refunded to the Interconnection Customer, as appropriate. The original Transmission Provider shall coordinate with the successor Transmission Provider to complete any Interconnection Study, as appropriate, that the original Transmission Provider has begun but has not completed. If Transmission Provider has tendered a draft LGIA to Interconnection Customer but Interconnection Customer has not either executed the LGIA or requested the filing of an unexecuted LGIA with FERC, unless otherwise provided, Interconnection Customer must complete negotiations with the successor Transmission Provider.

5.3 **Type of Interconnection Services.**

5.3.1 Any Interconnection Customer that submitted an Interconnection Request to be studied as a Network Resource under the previous Generator Interconnection Procedures will be deemed to have requested Network Resource Interconnection Service in accordance with this LGIP.

5.3.2 Any Interconnection Customer that submitted an Interconnection Request to be studied as a non-Network Resource under the previous Generator Interconnection Procedures will be deemed to have requested Energy

Resource Interconnection Service in accordance with this LGIP.

Section 6. Interconnection Feasibility Study.

6.1 Interconnection Feasibility Study Agreement.
Simultaneously with the acknowledgement of a valid Interconnection Request Transmission Provider shall provide to Interconnection Customer an Interconnection Feasibility Study Agreement in the form of Appendix 2. The Interconnection Feasibility Study Agreement shall specify that Interconnection Customer is responsible for the actual cost of the Interconnection Feasibility Study. Within five (5) Business Days following the Scoping Meeting Interconnection Customer shall specify for inclusion in the attachment to the Interconnection Feasibility Study Agreement the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection. Within five (5) Business Days following the Transmission Provider's receipt of such designation, Transmission Provider shall tender to Interconnection Customer the Interconnection Feasibility Study Agreement signed by Transmission Provider, which includes a good faith estimate of the cost for completing the Interconnection Feasibility Study. Interconnection Customer shall execute and deliver to Transmission Provider the Interconnection Feasibility Study Agreement along with a $10,000 deposit no later than thirty (30) Calendar Days after its receipt.

On or before the return of the executed Interconnection Feasibility Study Agreement to Transmission Provider, Interconnection Customer shall provide the technical data called for in Appendix 1, Attachment A.

If the Interconnection Feasibility Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting, a substitute Point of Interconnection identified by either Interconnection Customer or Transmission Provider, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and Restudies shall be completed pursuant to Section 6.4 as applicable. For the purpose of this Section 6.1, if Transmission Provider and Interconnection Customer cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 3.3.4, shall be the substitute.

If Interconnection Customer and Transmission Provider agree to forgo the Interconnection Feasibility Study, Transmission Provider will initiate an Interconnection System Impact Study under Section 7 of this LGIP and apply the $10,000 deposit towards the Interconnection System Impact Study.

6.2 Scope of Interconnection Feasibility Study.
The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the Transmission System.

The Interconnection Feasibility Study will consider the Base Case as well as all generating facilities (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are

directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC. The Interconnection Feasibility Study will consist of a power flow and short circuit analysis. The Interconnection Feasibility Study will provide a list of facilities and a nonbinding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

6.3 Interconnection Feasibility Study Procedures.
Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. Transmission Provider shall use Reasonable Efforts to complete the Interconnection Feasibility Study no later than forty-five (45) Calendar Days after Transmission Provider receives the fully executed Interconnection Feasibility Study Agreement. At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, Transmission Provider shall notify the Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If Transmission Provider is unable to complete the Interconnection Feasibility Study within that time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers and relevant power flow, short circuit and stability databases for the Interconnection Feasibility Study, subject to confidentiality arrangements consistent with Section 13.1.

6.3.1 Meeting with Transmission Provider.
Within ten (10) Business Days of providing an Interconnection Feasibility Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Feasibility Study.

6.4 Re-Study.
If Re-Study of the Interconnection Feasibility Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to Section 4.4, or re-designation of the Point of Interconnection pursuant to Section 6.1 Transmission Provider shall notify Interconnection Customer in writing. Such Re-Study shall take not longer than forty-five (45) Calendar Days from the date of the notice. Any cost of Re-Study shall be borne by the Interconnection Customer being restudied.

Section 7. Interconnection System Impact Study.

7.1 Interconnection System Impact Study Agreement.
Unless otherwise agreed, pursuant to the Scoping Meeting provided in Section 3.3.4, simultaneously with the delivery of the Interconnection Feasibility Study to Interconnection Customer, Transmission Provider shall provide to Interconnection Customer an Interconnection System Impact Study Agreement in the form of Appendix 3 to this LGIP. The Interconnection System Impact

Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Interconnection System Impact Study. Within three (3) Business Days following the Interconnection Feasibility Study results meeting, Transmission Provider shall provide to Interconnection Customer a nonbinding good faith estimate of the cost and timeframe for completing the Interconnection System Impact Study.

7.2 Execution of Interconnection System Impact Study Agreement. Interconnection Customer shall execute the Interconnection System Impact Study Agreement and deliver the executed Interconnection System Impact Study Agreement to Transmission Provider no later than thirty (30) Calendar Days after its receipt along with demonstration of Site Control, and a $50,000 deposit.

If Interconnection Customer does not provide all such technical data when it delivers the Interconnection System Impact Study Agreement, Transmission Provider shall notify Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection System Impact Study Agreement and Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed Interconnection System Impact Study Agreement or deposit.

If the Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting and the Interconnection Feasibility Study, a substitute Point of Interconnection identified by either Interconnection Customer or Transmission Provider, and acceptable to the other, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and restudies shall be completed pursuant to Section 7.6 as applicable. For the purpose of this Section 7.2, if Transmission Provider and Interconnection Customer cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 3.3.4, shall be the substitute.

Transmission Provider shall study the Interconnection Request at the level of service requested by the Interconnection Customer, unless otherwise required to study the full Generating Facility Capacity due to safety or reliability concerns.

7.3 Scope of Interconnection System Impact Study. The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the Transmission System. The Interconnection System Impact Study will consider the Base Case as well as all generating facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced: (i) are directly interconnected to the Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

The Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The Interconnection System Impact Study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Interconnection System Impact Study will provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

7.4 Interconnection System Impact Study Procedures.

Transmission Provider shall coordinate the Interconnection System Impact Study with any Affected System that is affected by the Interconnection Request pursuant to Section 3.5 above. Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. Transmission Provider shall use Reasonable Efforts to complete the Interconnection System Impact Study within ninety (90) Calendar Days after the receipt of the Interconnection System Impact Study Agreement or notification to proceed, study payment, and technical data. If Transmission Provider uses Clustering, Transmission Provider shall use Reasonable Efforts to deliver a completed Interconnection System Impact Study within ninety (90) Calendar Days after the close of the Queue Cluster Window.

At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection System Impact Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection System Impact Study. If Transmission Provider is unable to complete the Interconnection System Impact Study within the time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer all supporting documentation, workpapers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the Interconnection System Impact Study, subject to confidentiality arrangements consistent with Section 13.1.

7.5 Meeting with Transmission Provider.

Within ten (10) Business Days of providing an Interconnection System Impact Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection System Impact Study.

7.6 Re-Study.

If Re-Study of the Interconnection System Impact Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to Section 4.4, or re-designation of the Point of Interconnection pursuant to Section 7.2 Transmission Provider shall notify Interconnection Customer in writing. Such Re-Study shall take no longer than

sixty (60) Calendar Days from the date of notice. Any cost of Re-Study shall be borne by the Interconnection Customer being re-studied.

Section 8. Interconnection Facilities Study.

8.1 Interconnection Facilities Study Agreement.

Simultaneously with the delivery of the Interconnection System Impact Study to Interconnection Customer, Transmission Provider shall provide to Interconnection Customer an Interconnection Facilities Study Agreement in the form of Appendix 4 to this LGIP. The Interconnection Facilities Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Interconnection Facilities Study. Within three (3) Business Days following the Interconnection System Impact Study results meeting, Transmission Provider shall provide to Interconnection Customer a nonbinding good faith estimate of the cost and timeframe for completing the Interconnection Facilities Study. Interconnection Customer shall execute the Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement to Transmission Provider within thirty (30) Calendar Days after its receipt, together with the required technical data and the greater of $100,000 or Interconnection Customer’s portion of the estimated monthly cost of conducting the Interconnection Facilities Study.

8.1.1 Transmission Provider shall invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study each month. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice.

8.2 Scope of Interconnection Facilities Study.

The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Facility to the Transmission System. The Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Transmission Provider's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities.

8.3 Interconnection Facilities Study Procedures.

Transmission Provider shall coordinate the Interconnection Facilities Study with any Affected System pursuant to Section 3.5 above. Transmission Provider shall utilize existing studies to the extent practicable in performing the Interconnection Facilities Study. Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to Interconnection Customer within the following number of days after receipt of an executed Interconnection Facilities Study Agreement: ninety (90) Calendar Days, with no more than a +/- 20 percent cost estimate contained in the report; or one

hundred eighty (180) Calendar Days, if the Interconnection Customer requests a +/10 percent cost estimate.

At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Facilities Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection Facilities Study. If Transmission Provider is unable to complete the Interconnection Facilities Study and issue a draft Interconnection Facilities Study report within the time required, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required.

Interconnection Customer may, within thirty (30) Calendar Days after receipt of the draft report, provide written comments to Transmission Provider, which Transmission Provider shall include in the final report. Transmission Provider shall issue the final Interconnection Facilities Study report within fifteen (15) Business Days of receiving Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. Transmission Provider may reasonably extend such fifteen-day period upon notice to Interconnection Customer if Interconnection Customer's comments require Transmission Provider to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Report. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 13.1.

8.4 Meeting with Transmission Provider.

Within ten (10) Business Days of providing a draft Interconnection Facilities Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Facilities Study.

8.5 Re-Study.

If Re-Study of the Interconnection Facilities Study is required due to a higher queued project dropping out of the queue or a modification of a higher queued project pursuant to Section 4.4, Transmission Provider shall so notify Interconnection Customer in writing. Such Re-Study shall take no longer than sixty (60) Calendar Days from the date of notice. Any cost of Re-Study shall be borne by the Interconnection Customer being re-studied.

Section 9. Engineering & Procurement ("E&P") Agreement.

Prior to executing an LGIA, an Interconnection Customer may, in order to advance the implementation of its interconnection, request and Transmission Provider shall offer the Interconnection Customer, an E&P Agreement that authorizes Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. However, Transmission Provider shall not be obligated to offer an E&P Agreement if Interconnection Customer is in Dispute Resolution as a result of an allegation that Interconnection Customer has failed to meet any milestones or comply with any prerequisites specified in other parts of the LGIP. The E&P Agreement is an optional procedure and it will not alter the Interconnection Customer's Queue Position or In-Service Date. The E&P Agreement shall provide for Interconnection Customer to pay the cost of all activities authorized by Interconnection Customer and to make advance payments or provide other satisfactory security for such costs.

Interconnection Customer shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If Interconnection Customer withdraws its application for interconnection or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, Interconnection Customer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, Transmission Provider may elect: (i) to take title to the equipment, in which event Transmission Provider shall refund Interconnection Customer any amounts paid by Interconnection Customer for such equipment and shall pay the cost of delivery of such equipment, or (ii) to transfer title to and deliver such equipment to Interconnection Customer, in which event Interconnection Customer shall pay any unpaid balance and cost of delivery of such equipment.

Section 10. Optional Interconnection Study.

10.1 Optional Interconnection Study Agreement.

On or after the date when Interconnection Customer receives Interconnection System Impact Study results, the Interconnection Customer may request, and Transmission Provider shall perform a reasonable number of Optional Studies. The request shall describe the assumptions that Interconnection Customer wishes Transmission Provider to study within the scope described in Section 10.2. Within five (5) Business Days after receipt of a request for an Optional Interconnection Study, Transmission Provider shall provide to Interconnection Customer an Optional Interconnection Study Agreement in the form of Appendix 5.

The Optional Interconnection Study Agreement shall: (i) specify the technical data that Interconnection Customer must provide for each phase of the Optional Interconnection Study, (ii) specify Interconnection Customer's assumptions as to which Interconnection Requests with earlier queue priority dates will be excluded from the Optional Interconnection Study case and assumptions as to the type of interconnection service for Interconnection Requests remaining in the Optional Interconnection Study case, and (iii) Transmission Provider's estimate of the cost of the Optional Interconnection Study. To the extent known by Transmission Provider, such estimate shall include any costs expected to be incurred by any

Affected System whose participation is necessary to complete the Optional Interconnection Study. Notwithstanding the above, Transmission Provider shall not be required as a result of an Optional Interconnection Study request to conduct any additional Interconnection Studies with respect to any other Interconnection Request.

Interconnection Customer shall execute the Optional Interconnection Study Agreement within ten (10) Business Days of receipt and deliver the Optional Interconnection Study Agreement, the technical data and a $10,000 deposit to Transmission Provider.

10.2 Scope of Optional Interconnection Study.
The Optional Interconnection Study will consist of a sensitivity analysis based on the assumptions specified by Interconnection Customer in the Optional Interconnection Study Agreement. The Optional Interconnection Study will also identify Transmission Provider's Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide transmission service or Interconnection Service based upon the results of the Optional Interconnection Study. The Optional Interconnection Study shall be performed solely for informational purposes. Transmission Provider shall use Reasonable Efforts to coordinate the study with any Affected Systems that may be affected by the types of Interconnection Services that are being studied. Transmission Provider shall utilize existing studies to the extent practicable in conducting the Optional Interconnection Study.

10.3 Optional Interconnection Study Procedures.
The executed Optional Interconnection Study Agreement, the prepayment, and technical and other data called for therein must be provided to Transmission Provider within ten (10) Business Days of Interconnection Customer receipt of the Optional Interconnection Study Agreement. Transmission Provider shall use Reasonable Efforts to complete the Optional Interconnection Study within a mutually agreed upon time period specified within the Optional Interconnection Study Agreement. If Transmission Provider is unable to complete the Optional Interconnection Study within such time period, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required. Any difference between the study payment and the actual cost of the study shall be paid to Transmission Provider or refunded to Interconnection Customer, as appropriate. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation and workpapers and databases or data developed in the preparation of the Optional Interconnection Study, subject to confidentiality arrangements consistent with Section 13.1.

Section 11. Standard Large Generator Interconnection Agreement (LGIA).

11.1 Tender.
Interconnection Customer shall tender comments on the draft Interconnection Facilities Study Report within thirty (30) Calendar Days of receipt of the report. Within thirty (30) Calendar Days after the comments are submitted, Transmission Provider shall tender a draft LGIA, together with draft appendices. The draft LGIA shall be in the form of Transmission Provider's FERC-approved standard form

LGIA, which is in Appendix 6. Interconnection Customer shall execute and return the completed draft appendices within thirty (30) Calendar Days.

11.2 Negotiation.

Notwithstanding Section 11.1, at the request of Interconnection Customer Transmission Provider shall begin negotiations with Interconnection Customer concerning the appendices to the LGIA at any time after Interconnection Customer executes the Interconnection Facilities Study Agreement. Transmission Provider and Interconnection Customer shall negotiate concerning any disputed provisions of the appendices to the draft LGIA for not more than sixty (60) Calendar Days after tender of the final Interconnection Facilities Study Report. If Interconnection Customer determines that negotiations are at an impasse, it may request termination of the negotiations at any time after tender of the draft LGIA pursuant to Section 11.1 and request submission of the unexecuted LGIA with FERC or initiate Dispute Resolution procedures pursuant to Section 13.5. If Interconnection Customer requests termination of the negotiations, but within sixty (60) Calendar Days thereafter fails to request either the filing of the unexecuted LGIA or initiate Dispute Resolution, it shall be deemed to have withdrawn its Interconnection Request. Unless otherwise agreed by the Parties, if the Interconnection Customer has not executed the LGIA, requested filing of an unexecuted LGIA, or initiated Dispute Resolution procedures pursuant to Section 13.5 within sixty (60) Calendar Days of tender of draft LGIA, it shall be deemed to have withdrawn its Interconnection Request. Transmission Provider shall provide to Interconnection Customer a final LGIA within fifteen (15) Business Days after the completion of the negotiation process.

11.3 Execution and Filing.

Within fifteen (15) Business Days after receipt of the final LGIA, Interconnection Customer shall provide Transmission Provider (A) reasonable evidence that continued Site Control or (B) posting of $250,000, non-refundable additional security, which shall be applied toward future construction costs. At the same time, Interconnection Customer also shall provide reasonable evidence that one or more of the following milestones in the development of the Large Generating Facility, at the Interconnection Customer election, has been achieved: (i) the execution of a contract for the supply or transportation of fuel to the Large Generating Facility; (ii) the execution of a contract for the supply of cooling water to the Large Generating Facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Large Generating Facility; (iv) execution of a contract for the sale of electric energy or capacity from the Large Generating Facility; or (v) application for an air, water, or land use permit.

Interconnection Customer shall either: (i) execute two originals of the tendered LGIA and return them to Transmission Provider; or (ii) request in writing that Transmission Provider file with FERC an LGIA in unexecuted form. As soon as practicable, but not later than ten (10) Business Days after receiving either the two executed originals of the tendered LGIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or the request to file an unexecuted LGIA, Transmission Provider shall file the LGIA with FERC, together with its explanation of any matters as to which Interconnection Customer and Transmission Provider disagree and support for the costs that

Transmission Provider proposes to charge to Interconnection Customer under the LGIA. An unexecuted LGIA should contain terms and conditions deemed appropriate by Transmission Provider for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted LGIA, they may proceed pending FERC action.

11.4 Commencement of Interconnection Activities.
If Interconnection Customer executes the final LGIA, Transmission Provider and Interconnection Customer shall perform their respective obligations in accordance with the terms of the LGIA, subject to modification by FERC. Upon submission of an unexecuted LGIA, Interconnection Customer and Transmission Provider shall promptly comply with the unexecuted LGIA, subject to modification by FERC.

Section 12. Construction of Transmission Provider's Interconnection Facilities and Network Upgrades.

12.1 Schedule.
Transmission Provider and Interconnection Customer shall negotiate in good faith concerning a schedule for the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades.

12.2 Construction Sequencing.

12.2.1 General

In general, the In-Service Date of an Interconnection Customers seeking interconnection to the Transmission System will determine the sequence of construction of Network Upgrades.

12.2.2 Advance Construction of Network Upgrades that are an Obligation of an Entity other than Interconnection Customer

An Interconnection Customer with an LGIA, in order to maintain its In-Service Date, may request that Transmission Provider advance to the extent necessary the completion of Network Upgrades that: (i) were assumed in the Interconnection Studies for such Interconnection Customer, (ii) are necessary to support such In-Service Date, and (iii) would otherwise not be completed, pursuant to a contractual obligation of an entity other than Interconnection Customer that is seeking interconnection to the Transmission System, in time to support such In-Service Date. Upon such request, Transmission Provider will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Provider: (i) any associated expediting costs and (ii) the cost of such Network Upgrades.

Transmission Provider will refund to Interconnection Customer

both the expediting costs and the cost of Network Upgrades, in accordance with Article 11.4 of the LGIA. Consequently, the entity with a contractual obligation to construct such Network Upgrades shall be obligated to pay only that portion of the costs of the Network Upgrades that Transmission Provider has not refunded to the Interconnection Customer. Payment by that entity shall be due on the date that it would have been due had there been no request for advance construction. Transmission Provider shall forward to Interconnection Customer the amount paid by the entity with a contractual obligation to construct the Network Upgrades as payment in full for the outstanding balance owed to Interconnection Customer. Transmission Provider then shall refund to that entity the amount that it paid for the Network Upgrades, in accordance with Article 11.4 of the LGIA.

12.2.3 Advancing Construction of Network Upgrades that are Part of an Expansion Plan of the Transmission Provider

An Interconnection Customer with an LGIA, in order to maintain its In-Service Date, may request that Transmission Provider advance to the extent necessary the completion of Network Upgrades that: (i) are necessary to support such In-Service Date and (ii) would otherwise not be completed, pursuant to an expansion plan of Transmission Provider, in time to support such In-Service Date. Upon such request, Transmission Provider will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Provider any associated expediting costs. Interconnection Customer shall be entitled to transmission credits, if any, for any expediting costs paid.

12.2.4 Amended Interconnection System Impact Study

An Interconnection System Impact Study will be amended to determine the facilities necessary to support the requested In-Service Date. This amended study will include those transmission and Large Generating Facilities that are expected to be in service on or before the requested In-Service Date.

Section 13 Miscellaneous

13.1 Confidentiality.

Confidential Information shall include, without limitation, all information relating to a Party’s technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of an LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally

informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

13.1.1 Scope.

Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of the LGIA; or (6) is required, in accordance with Section 13.1.6, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under the LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

13.1.2 Release of Confidential Information.

Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements) employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this Section 13.1 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Section 13.1.

13.1.3 Rights.

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

13.1.4 No Warranties.

By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

13.1.5 Standard of Care.

Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under these procedures or its regulatory requirements.

13.1.6 Order of Disclosure.

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of the LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

13.1.7 Remedies.

The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Section 13.1. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its

obligations under this Section 13.1, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Section 13.1, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Section 13.1.

13.1.8 Disclosure to FERC or its Staff, or a State.

Notwithstanding anything in this Section 13.1 to the contrary, and pursuant to 18 C.F.R. section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to the LGIP, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, consistent with applicable state rules and regulations.

13.1.9 Subject to the exception in Section 13.1.8, any information that a Party claims is competitively sensitive, commercial or financial information ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIP or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a subregional, regional or national reliability organization or planning group. The Party asserting confidentiality

shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

13.1.10 This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

13.1.11 Transmission Provider shall, at Interconnection Customer's election, destroy, in a confidential manner, or return the Confidential Information provided at the time of Confidential Information is no longer needed.

13.2 Delegation of Responsibility.

Transmission Provider may use the services of subcontractors as it deems appropriate to perform its obligations under this LGIP. Transmission Provider shall remain primarily liable to Interconnection Customer for the performance of such subcontractors and compliance with its obligations of this LGIP. The subcontractor shall keep all information provided confidential and shall use such information solely for the performance of such obligation for which it was provided and no other purpose.

13.3 Obligation for Study Costs.

Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Studies. Any difference between the study deposit and the actual cost of the applicable Interconnection Study shall be paid by or refunded, except as otherwise provided herein, to Interconnection Customer or offset against the cost of any future Interconnection Studies associated with the applicable Interconnection Request prior to beginning of any such future Interconnection Studies. Any invoices for Interconnection Studies shall include a detailed and itemized accounting of the cost of each Interconnection Study. Interconnection Customer shall pay any such undisputed costs within thirty (30) Calendar Days of receipt of an invoice therefor. Transmission Provider shall not be obligated to perform or continue to perform any studies unless Interconnection Customer has paid all undisputed amounts in compliance herewith.

13.4 Third Parties Conducting Studies.

If (i) at the time of the signing of an Interconnection Study Agreement there is disagreement as to the estimated time to complete an Interconnection Study, (ii) Interconnection Customer receives notice pursuant to Sections 6.3, 7.4 or 8.3

that Transmission Provider will not complete an Interconnection Study within the applicable timeframe for such Interconnection Study, or (iii) Interconnection Customer receives neither the Interconnection Study nor a notice under Sections 6.3, 7.4 or 8.3 within the applicable timeframe for such Interconnection Study, then Interconnection Customer may require Transmission Provider to utilize a third party consultant reasonably acceptable to Interconnection Customer and Transmission Provider to perform such Interconnection Study under the direction of Transmission Provider. At other times, Transmission Provider may also utilize a third party consultant to perform such Interconnection Study, either in response to a general request of Interconnection Customer, or on its own volition.

In all cases, use of a third party consultant shall be in accord with Article 26 of the LGIA (Subcontractors) and limited to situations where Transmission Provider determines that doing so will help maintain or accelerate the study process for Interconnection Customer's pending Interconnection Request and not interfere with Transmission Provider's progress on Interconnection Studies for other pending Interconnection Requests. In cases where Interconnection Customer requests use of a third party consultant to perform such Interconnection Study, Interconnection Customer and Transmission Provider shall negotiate all of the pertinent terms and conditions, including reimbursement arrangements and the estimated study completion date and study review deadline. Transmission Provider shall convey all workpapers, data bases, study results and all other supporting documentation prepared to date with respect to the Interconnection Request as soon as soon as practicable upon Interconnection Customer's request subject to the confidentiality provision in Section 13.1. In any case, such third party contract may be entered into with either Interconnection Customer or Transmission Provider at Transmission Provider’s discretion. In the case of (iii) Interconnection Customer maintains its right to submit a claim to Dispute Resolution to recover the costs of such third party study. Such third party consultant shall be required to comply with this LGIP, Article 26 of the LGIA (Subcontractors), and the relevant Tariff procedures and protocols as would apply if Transmission Provider were to conduct the Interconnection Study and shall use the information provided to it solely for purposes of performing such services and for no other purposes. Transmission Provider shall cooperate with such third party consultant and Interconnection Customer to complete and issue the Interconnection Study in the shortest reasonable time.

13.5 Disputes.

13.5.1 Submission.

In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with the LGIA, the LGIP, or their performance, such Party (the “disputing Party”) shall provide the other Party with written notice of the dispute or claim (“Notice of Dispute”). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party’s receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

13.5.2 External Arbitration Procedures.

Any arbitration initiated under these procedures shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association (“Arbitration Rules”) and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Section 13, the terms of this Section 13 shall prevail.

13.5.3 Arbitration Decisions.

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the LGIA

and LGIP and shall have no power to modify or change any provision of the LGIA and LGIP in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

13.5.4 Costs.

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

13.6 Local Furnishing Bonds

13.6.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds.

This provision is applicable only to a Transmission Provider that has financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local furnishing bonds"). Notwithstanding any other provision of this LGIA and LGIP, Transmission Provider shall not be required to provide Interconnection Service to Interconnection Customer pursuant to this LGIA and LGIP if the provision of such Interconnection Service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance Transmission Provider's facilities that would be used in providing such Interconnection Service.

13.6.2 Alternative Procedures for Requesting Interconnection Service.

If Transmission Provider determines that the provision of Interconnection Service requested by Interconnection Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such Interconnection Service, it shall advise the Interconnection Customer within thirty (30) Calendar Days of receipt of the Interconnection Request.

Interconnection Customer thereafter may renew its request for

interconnection using the process specified in Article 5.2(ii) of the Transmission Provider's Tariff.

APPENDIX 1 to LGIP
INTERCONNECTION REQUEST

1.The undersigned Interconnection Customer submits this request to interconnect its Large Generating Facility with Transmission Provider's Transmission System pursuant to a Tariff.

2.This Interconnection Request is for (check one):

____A proposed new Large Generating Facility.

____An increase in the generating capacity or a Material Modification of an existing Generating Facility.

3.The type of interconnection service requested (check one)

___Energy Resource Interconnection Service

___Network Resource Interconnection Service

4.____ Check here only if Interconnection Customer requesting Network Resource Interconnection Service also seeks to have it Generating Facility studied for Energy Resource Interconnection Service.

5.Interconnection Customer provides the following information:

a. Address or location or the proposed new Large Generating Facility site (to the extent known) or, in the case of an existing Generating Facility, the name and specific location of the existing Generating Facility;

b. Maximum summer at ____ degrees C and winter at degrees C megawatt electrical output of the proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of an existing Generating Facility;

c. General description of the equipment configuration;

d. Commercial Operation Date (Day, Month, and Year);

e. Name, address, telephone number, and e-mail address of the Interconnection Customer's contact person;

f. Approximate location of the proposed Point of Interconnection (optional); and

g. Interconnection Customer Data (set forth in Attachment A)

h. Primary frequency response operating range for electric storage resources.

6. Applicable deposit amount as specified in the LGIP.

7. Evidence of Site Control as specified in the LGIP (check one)

___ Is attached to this Interconnection Request

___ Will be provided at a later date in accordance with this LGIP

8. This Interconnection Request shall be submitted to the representative indicated below:

[To be completed by Transmission Provider]

9. Representative of the Interconnection Customer to contact:

[To be completed by Interconnection Customer]

10. This Interconnection Request is submitted by:

Name of Interconnection Customer:

By (signature):

Name (type or print): ______________________________

Title: ______________________________

Date: ______________________________

Attachment A (page 1) To Appendix 1

Interconnection Request

LARGE GENERATING FACILITY DATA UNIT RATINGS

kVA ____________________________ °F _______________ Voltage ____________
Power Factor
Speed (RPM) Connection (e.g. Wye)____________
Short Circuit Ratio Frequency, Hertz
Stator Amperes at Rated kVA __________________________ Field Volts
Max Turbine MW _________________________ °F ______________
Primary frequency response operating range for electric storage sources
Minimum State of Charge ___________________
Maximum State of Charge ___________________

COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = kW sec/kVA
Moment-of-Inertia, WR2 = ____lb. ft.2

REACTANCE DATA (PER UNIT-RATED KVA) DIRECT AXIS QUADRATURE AXIS

Synchronous – saturated	Xdv ____________	Xqv _________
Synchronous – unsaturated	Xdi ____________	Xqi _________
Transient – saturated	XNdv ___________	XNqv ________
Transient – unsaturated	XNdi ___________	XNqi ________
Subtransient – saturated	XOdv ___________	XOqv ________
Subtransient – unsaturated	XOdi ___________	XOqi ________
Negative Sequence – saturated	X2v _________	
Negative Sequence – unsaturated X2i ___________________________		
Zero Sequence – saturated	X0v _________	
Zero Sequence – unsaturated	X0i _________	
Leakage Reactance	Xlm _________	

FIELD TIME CONSTANT DATA (SEC)

Open Circuit	TNdo ____________	TNqo_______
Three-Phase Short Circuit Transient	TNd3 ____________	TNq________
Line to Line Short Circuit Transient	TNd2 _________	
Line to Neutral Short Circuit Transient	TNd1 ________	
Short Circuit Subtransient	TOd ____________	TOq________
Open Circuit Subtransient	TOdo ____________	TOqo_______

ARMATURE TIME CONSTANT DATA (SEC)

Three Phase Short Circuit	Ta3 ________
Line to Line Short Circuit	Ta2 ________

Line to Neutral Short Circuit Ta1 ________

NOTE: If requested information is not applicable, indicate by marking "N / A."

Attachment A (page 2) To Appendix 1
Interconnection Request

MW CAPABILITY AND PLANT CONFIGURATION LARGE GENERATING FACILITY DATA

ARMATURE WINDING RESISTANCE DATA (PER UNIT)

Positive R1 __________
Negative R2 __________

Zero R0

Rotor Short Time Thermal Capacity I22t
Field Current at Rated kVA, Armature Voltage and PF = ________________________________ amps
Field Current at Rated kVA and Armature Voltage, 0 PF = ________________________________ amps
Three Phase Armature Winding Capacitance = microfarad
Field Winding Resistance = ohms °C
Armature Winding Resistance (Per Phase) = ohms °C

CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

Attachment A (page 3) To Appendix 1
Interconnection Request

GENERATOR STEP-UP TRANSFORMER DATA

RATINGS

Capacity Self-cooled/maximum nameplate

___________________________/_________________kVA

Voltage Ratio Generator side/System side

___________________________/_________________kV

Winding Connections Low V/High V (Delta or Wye)

___________________________/_________________

Fixed Taps Available ____

Present Tap Setting ____

IMPEDANCE

Positive Z1 (on self-cooled kVA rating)_______________________% __________ X/R

Zero Z0 (on self-cooled kVA rating)_______________________% __________ X/R

Attachment A (page 4) To Appendix 1
Interconnection Request

EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request: ______________________

Elevation: ____________ _________ Single Phase ___________ Three Phase

Inverter manufacturer, model name, number, and version:

List of adjustable setpoints for the protective equipment or software:

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device then they shall be provided and discussed at Scoping Meeting.

Attachment A (page 5) To Appendix 1
Interconnection Request

INDUCTION GENERATORS:

(*) Field Volts: ____________________
(*) Field Amperes: __________________
(*) Motoring Power (kW): ____________
(*) Neutral Grounding Resistor (If Applicable): ___________________
(*) I2 ^{2}t or K (Heating Time Constant): _________________
(*) Rotor Resistance: ________________
(*) Stator Resistance:_________________
(*) Stator Reactance: _________________
(*) Rotor Reactance: ________________
(*) Magnetizing Reactance: _________________
(*) Short Circuit Reactance:_________________
(*) Exciting Current: ____________________
(*) Temperature Rise: _____________________
(*) Frame Size: ________________
(*) Design Letter: _________________
(*) Reactive Power Required In Vars (No Load):_________________
(*) Reactive Power Required In Vars (Full Load): ________________
(*) Total Rotating Inertia, H:______________Per Unit on KVA Base

Note: Please consult Transmission Provider prior to submitting the Interconnection Request to determine if the information designated by (*) is required.

APPENDIX 2 to LGIP
INTERCONNECTION FEASIBILITY STUDY AGREEMENT

THIS AGREEMENT is made and entered into this day of, 20___
by and between ______________________, a ____________________ organized and existing under the laws of the State of __________________ , ("Interconnection Customer,") and
_________________________________ a____
______________ existing under the laws of the State of _________________, ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated ; and

WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System; and

WHEREAS, Interconnection Customer has requested Transmission Provider to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Large Generating Facility to the Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved LGIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed an Interconnection Feasibility Study consistent with Section 6.0 of this LGIP in accordance with the Tariff.

3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection Feasibility Study shall be based on the technical information provided by Interconnection Customer in the Interconnection Request, as may be modified as the result of the Scoping Meeting. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the

Interconnection Feasibility Study and as designated in accordance with Section 3.3.4 of the LGIP. If, after the designation of the Point of Interconnection pursuant to Section 3.3.4 of the LGIP, Interconnection Customer modifies its Interconnection Request pursuant to Section 4.4, the time to complete the Interconnection Feasibility Study may be extended.

5.0 The Interconnection Feasibility Study report shall provide the following information:

- preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- preliminary identification of any thermal overload or voltage limit violations resulting from the interconnection; and

- preliminary description and non-bonding estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit and power flow issues.

6.0 Interconnection Customer shall provide a deposit of $10,000 for the performance of the Interconnection Feasibility Study.

Upon receipt of the Interconnection Feasibility Study Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Feasibility Study.

Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Miscellaneous. The Interconnection Feasibility Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the LGIP and the LGIA.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ____ By:

Title: _____________________________________ Title: ________________________

Date: _____________________________________ Date:_________________________

[Insert name of Interconnection Customer]

By:

Title: _________________________________

Date: __________________________________

Attachment A to Appendix 2 Interconnection Feasibility Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE INTERCONNECTION FEASIBILITY STUDY

The Interconnection Feasibility Study will be based upon the information set forth in the Interconnection Request and agreed upon in the Scoping Meeting held on:

Designation of Point of Interconnection and configuration to be studied. Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer and Transmission Provider]

APPENDIX 3 to LGIP
INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this day of__________________________________ , 20 by and between _____________________, a ___________________ organized and existing under the laws of the State of _________________ , ("Interconnection Customer,") and ________________________________ a_______________________________________ ______________ existing under the laws of the State of _________________, ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the

Interconnection Request submitted by Interconnection Customer dated ; and

WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System;

WHEREAS, Transmission Provider has completed an Interconnection Feasibility Study (the "Feasibility Study") and provided the results of said study to Interconnection Customer[1]; and

WHEREAS, Interconnection Customer has requested Transmission Provider to perform an Interconnection System Impact Study to assess the impact of interconnecting the Large Generating Facility to the Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved LGIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause to be performed an Interconnection System Impact Study consistent with Section 7.0 of this LGIP in accordance with the Tariff.

3.0The scope of the Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study and the technical information provided by Interconnection Customer in the Interconnection Request, subject to any modifications in accordance with Section 4.4 of the LGIP. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Customer System Impact Study. If Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the Interconnection System Impact Study may be extended.

5.0The Interconnection System Impact Study report shall provide the following information: identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection; identification of any thermal overload or voltage limit violations resulting from the interconnection; identification of any instability or inadequately damped response to system disturbances resulting from the interconnection and description and non-binding, good faith estimated cost of facilities required to interconnect the Large Generating Facility to the Transmission System and to address the identified short circuit, instability, and power flow issues.

6.0 Interconnection Customer shall provide a deposit of $50,000 for the performance of the Interconnection System Impact Study. Transmission Provider's good faith estimate for the

time of completion of the Interconnection System Impact Study is [insert date].

Upon receipt of the Interconnection System Impact Study, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection System Impact Study. Any difference between the deposit and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Miscellaneous. The Interconnection System Impact Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, that are consistent with regional practices, Applicable Laws and Regulations and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the LGIP and the LGIA.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ______________________________ By:

Title: ______________________________ Title: ______________________________

Date: ______________________________ Date: ______________________________

[Insert name of Interconnection Customer]

By:

Title: ______________________________

Date: ______________________________

Attachment A To Appendix 3
Interconnection System Impact
Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE INTERCONNECTION SYSTEM IMPACT STUDY

The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study, subject to any modifications in accordance

with Section 4.4 of the LGIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied. Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer and Transmission Provider]

APPENDIX 4 to LGIP
INTERCONNECTION FACILITIES STUDY AGREEMENT

THIS AGREEMENT is made and entered into this day of, _______________20 by and between ______________________, a ____________________ organized and existing under the laws of the State of _________________ , ("Interconnection Customer,") and ________________________________ a____ ______________ existing under the laws of the State of _________________, ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated; and

WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility with the Transmission System;

WHEREAS, Transmission Provider has completed an Interconnection System Impact Study (the "System Impact Study") and provided the results of said study to Interconnection Customer; and

WHEREAS, Interconnection Customer has requested Transmission Provider to perform an Interconnection Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Large Generating Facility to the Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved LGIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause an Interconnection Facilities Study consistent with Section 8.0 of this LGIP to be performed in accordance with the Tariff.

3.0 The scope of the Interconnection Facilities Study shall be subject to the assumptions set forth in Attachment A and the data provided in Attachment B to this Agreement.

4.0 The Interconnection Facilities Study report (i) shall provide a description, estimated cost of (consistent with Attachment A), schedule for required facilities to interconnect the Large Generating Facility to the Transmission System and (ii) shall address the short circuit, instability, and power flow issues identified in the Interconnection System Impact Study.

5.0 Interconnection Customer shall provide a deposit of $100,000 for the performance of the Interconnection Facilities Study. The time for completion of the Interconnection Facilities Study is specified in Attachment A.

Transmission Provider shall invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study each month. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice.

6.0 Miscellaneous. The Interconnection Facility Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the LGIP and the LGIA.**IN WITNESS WHEREOF,** the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ______________________________ By:

Title: ______________________________ Title: ______________________________

Date: ______________________________ Date:______________________________

[Insert name of Interconnection Customer]

By:

Title: ______________________________

Date: ______________________________

Attachment A To Appendix 4
Interconnection Facilities Study Agreement

INTERCONNECTION CUSTOMER SCHEDULE ELECTION FOR CONDUCTING THE INTERCONNECTION FACILITIES STUDY

Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to Interconnection Customer within the following number of days after of receipt of an executed copy of this Interconnection Facilities Study Agreement:

- ninety (90) Calendar Days with no more than a +/- 20 percent cost estimate contained in the report, or

- one hundred eighty (180) Calendar Days with no more than a +/- 10 percent cost estimate contained in the report.

Attachment B (page 1)
Appendix 4
Interconnection Facilities Study Agreement

DATA FORM TO BE PROVIDED BY INTERCONNECTION CUSTOMER WITH THE INTERCONNECTION FACILITIES STUDY AGREEMENT

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections:

On the one line indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one line indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

Will an alternate source of auxiliary power be available during CT/PT maintenance? Yes No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? ___________________________ Yes No (Please indicate on one line).

What type of control system or PLC will be located at the Interconnection Customer's Large Generating Facility?

What protocol does the control system or PLC use?

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

Physical dimensions of the proposed interconnection station:

Bus length from generation to interconnection station:

Line length from interconnection station to Transmission Provider's transmission line.

Tower number observed in the field. (Painted on tower leg)*

Number of third party easements required for transmission lines*:

* To be completed in coordination with Transmission Provider.

Is the Large Generating Facility in the Transmission Provider's service area?

________________ Yes ________No Local provider: ____

Please provide proposed schedule dates:

Begin Construction Date: ______________________

Generator step-up transformer receives back feed power Date: ______________________

Generation Testing Date: ______________________

Commercial Operation Date: ______________________

APPENDIX 5 to LGIP
OPTIONAL INTERCONNECTION STUDY AGREEMENT

THIS AGREEMENT is made and entered into this day of ___________________________________, 20 by and between ______________________, a ____________________ organized and existing under the laws of the State of _________________ , ("Interconnection Customer,") and _________________________________ a____ ______________ existing under the laws of the State of _________________, ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated ;

WHEREAS, Interconnection Customer is proposing to establish an interconnection with the Transmission System; and

WHEREAS, Interconnection Customer has submitted to Transmission Provider an Interconnection Request; and

WHEREAS, on or after the date when Interconnection Customer receives the Interconnection System Impact Study results, Interconnection Customer has further requested that Transmission Provider prepare an Optional Interconnection Study;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved LGIP.
.

2.0 Interconnection Customer elects and Transmission Provider shall cause an Optional Interconnection Study consistent with Section 10.0 of this LGIP to be performed in accordance with the Tariff.

3.0 The scope of the Optional Interconnection Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Optional Interconnection Study shall be performed solely for informational purposes.

5.0 The Optional Interconnection Study report shall provide a sensitivity analysis based on the assumptions specified by Interconnection Customer in Attachment A to this Agreement. The Optional Interconnection Study will identify Transmission Provider's Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide transmission service or interconnection service based upon the assumptions specified by Interconnection Customer in Attachment A.

6.0 Interconnection Customer shall provide a deposit of $10,000 for the performance of the Optional Interconnection Study. Transmission Provider's good faith estimate for the time of completion of the Optional Interconnection Study is [insert date].

Upon receipt of the Optional Interconnection Study, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Optional Study.

Any difference between the initial payment and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Miscellaneous. The Optional Interconnection Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the LGIP and the LGIA.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider or Transmission Owner, if applicable]

By: ______________________________ By:

Title: ______________________________ Title: ______________________________

Date: ______________________________ Date:______________________________

[Insert name of Interconnection Customer]

By:

Title: ______________________________

Date: ______________________________

ASSUMPTIONS USED IN CONDUCTING THE OPTIONAL INTERCONNECTION STUDY

[To be completed by Interconnection Customer consistent with Section 10 of the LGIP.]

Appendix 6 to the Standard Large
Generator Interconnection Procedures

STANDARD LARGE GENERATOR

INTERCONNECTION AGREEMENT (LGIA)

(For Generating Facilities Larger Than 20 MWs)TABLE OF CONTENTS

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this ____ day of ___________ 20__, by and between, __________________, a organized and existing under the laws of the State/Commonwealth of _______ ("Interconnection Customer" with a Large Generating Facility), and Tri-State Generation and Transmission Association, Inc., a cooperative corporation organized and existing under the laws of the State of Colorado ("Transmission Provider and/or Transmission Owner"). Interconnection Customer and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties."

Recitals

WHEREAS, Transmission Provider operates the Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and,

WHEREAS, Interconnection Customer and Transmission Provider have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility with the Transmission

System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).

Article 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the Regional Entity, as defined by Section 215 of the Federal Power Act, applicable to the Transmission System to which the Generating Facility is directly interconnected.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is

studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the

Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy

production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission Provider's Transmission System. The scope of the study is defined in Section 8 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 6 of the Standard Large Generator Interconnection Procedures.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Corporation or its successor organization.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network

Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Queue Position shall mean the order of a valid Interconnection Request relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard Large Generator Interconnection Agreement to the extent necessary.

Transmission Provider shall mean Tri-State Generation and Transmission Association, Inc., the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Article 2. Effective Date, Term, and Termination

2.1 Effective Date. This LGIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this LGIA with FERC upon execution in accordance with Article 3.1, if required.

2.2 Term of Agreement. Subject to the provisions of Article 2.3, this LGIA shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as Interconnection Customer may request (Term to be specified in individual agreements) and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures

2.3.1 Written Notice. This LGIA may be terminated by Interconnection Customer after giving Transmission Provider ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default. Either Party may terminate this LGIA in accordance with Article 17.

2.3.3 Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this LGIA, which notice has been accepted for filing by FERC.

2.4 Termination Costs. If a Party elects to terminate this Agreement pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party, as of the date of the other Party's receipt of such notice of termination, that are the responsibility of the Terminating Party under this LGIA. In the event of termination by a Party, the Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this LGIA, unless otherwise ordered or approved by FERC:

2.4.1 With respect to any portion of Transmission Provider's Interconnection Facilities that have not yet been constructed or installed, Transmission Provider shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Provider shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Provider for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Provider shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Provider to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this LGIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which Transmission Provider has incurred expenses and has not been reimbursed by Interconnection Customer.

2.4.2 Transmission Provider may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Provider shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA,

Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 Disconnection. Upon termination of this LGIA, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 Survival. This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

Article 3. Regulatory Filings

3.1 Filing. Transmission Provider shall file this LGIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this LGIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

Article 4. Scope of Service

4.1 Interconnection Product Options. Interconnection Customer has selected the following (checked) type of Interconnection Service:

4.1.1 Energy Resource Interconnection Service.

4.1.1.1 The Product. Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interconnection Service, Transmission Provider shall construct facilities identified in Attachment A.

4.1.1.2 Transmission Delivery Service Implications. Under Energy Resource Interconnection Service, Interconnection Customer will be eligible to inject power from the Large Generating Facility into and deliver power across the interconnecting Transmission Provider's Transmission System

on an "as available" basis up to the amount of MWs identified in the applicable stability and steady state studies to the extent the upgrades initially required to qualify for Energy Resource Interconnection Service have been constructed. Where eligible to do so (e.g., PJM, ISO-NE, NYISO), Interconnection Customer may place a bid to sell into the market up to the maximum identified Large Generating Facility output, subject to any conditions specified in the interconnection service approval, and the Large Generating Facility will be dispatched to the extent Interconnection Customer's bid clears. In all other instances, no transmission delivery service from the Large Generating Facility is assured, but Interconnection Customer may obtain Point-to-Point Transmission Service, Network Integration Transmission Service, or be used for secondary network transmission service, pursuant to Transmission Provider's Tariff, up to the maximum output identified in the stability and steady state studies. In those instances, in order for Interconnection Customer to obtain the right to deliver or inject energy beyond the Large Generating Facility Point of Interconnection or to improve its ability to do so, transmission delivery service must be obtained pursuant to the provisions of Transmission Provider's Tariff. The Interconnection Customer's ability to inject its Large Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of Transmission Provider's Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of firm Point-to-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

4.1.2 Network Resource Interconnection Service.

4.1.2.1 **The Product.** Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interconnection Service, Transmission Provider shall construct the facilities identified in Attachment A to this LGIA.

4.1.2.2 **Transmission Delivery Service Implications.** Network Resource Interconnection Service allows Interconnection Customer's Large Generating Facility to be designated by any

Network Customer under the Tariff on Transmission Provider's Transmission System as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Large Generating Facility in the same manner as it accesses Network Resources. A Large Generating Facility receiving Network Resource Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Large Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Large Generating Facility has not been designated as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or firm Point-to-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Large Generating Facility to any particular load on Transmission Provider's Transmission System without incurring congestion costs. In the event of transmission constraints on Transmission Provider's Transmission System, Interconnection Customer's Large Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that Interconnection Customer's Large Generating Facility be designated as a Network Resource by a Network Service Customer under the Tariff or that

Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Large Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interconnection Service, any future transmission service request for delivery from the Large Generating Facility within Transmission Provider's Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Large Generating Facility be undertaken, regardless of whether or not such Large Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Large Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Large Generating Facility outside Transmission Provider's Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

4.2 Provision of Service. Transmission Provider shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 Performance Standards. Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the LGIA and submit the amendment to FERC for approval.

4.4 No Transmission Delivery Service. The execution of this LGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.5 Interconnection Customer Provided Services. The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.6.

Article 5. Interconnection Facilities Engineering, Procurement, and Construction

5.1 Options. Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either Standard Option or Alternate Option set forth below for completion of Transmission Provider's Interconnection Facilities and Network Upgrades, as set forth in Appendix A, Interconnection Facilities and Network Upgrades, and such dates and selected option shall be set forth in Appendix B, Milestones.

5.1.1 Standard Option. Transmission Provider shall design, procure, and construct Transmission Provider's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Provider shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Provider reasonably expects that it will not be able to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the specified dates, Transmission Provider shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 Alternate Option. If the dates designated by Interconnection Customer are acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities by the designated dates.

If Transmission Provider subsequently fails to complete Transmission Provider's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B, Milestones; Transmission Provider shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable RTO or ISO refuses to grant clearances to install equipment.

5.1.3 Option to Build. If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume

responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. Transmission Provider and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 Negotiated Option. If Interconnection Customer elects not to exercise its option under Article 5.1.3, Option to Build, Interconnection Customer shall so notify Transmission Provider within thirty (30) Calendar Days, and the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives, or the procurement and construction of a portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades by Interconnection Customer pursuant to which Transmission Provider is responsible for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, Transmission Provider shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades pursuant to article 5.1.1, Standard Option.

5.2 General Conditions Applicable to Option to Build. If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Provider;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Provider shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and

shall promptly respond to requests for information from Transmission Provider;

(5) at any time during construction, Transmission Provider shall have the right to gain unrestricted access to Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;
(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Provider, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider for claims arising from Interconnection Customer's construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) Interconnection Customer shall transfer control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Provider's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Provider;

(10) Transmission Provider shall approve and accept for operation and maintenance Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information, and any other documents that are reasonably required by Transmission Provider to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

5.3 Liquidated Damages. The actual damages to Interconnection Customer, in the event Transmission Provider's Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Provider pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Provider to Interconnection Customer in the event that Transmission Provider does not complete any portion of Transmission Provider's Interconnection Facilities or Network Upgrades by

the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades, in the aggregate, for which Transmission Provider has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades for which Transmission Provider has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Provider to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Provider's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for the Large Generating Facility's Trial Operation or to export power from the Large Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for Large Generating Facility's Trial Operation or to export power from the Large Generating Facility, but for Transmission Provider's delay; (2) Transmission Provider's failure to meet the specified dates is the result of the action or inaction of Interconnection Customer or any other Interconnection Customer who has entered into an LGIA with Transmission Provider or any cause beyond Transmission Provider's reasonable control or reasonable ability to cure; (3) the Interconnection Customer has assumed responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 Power System Stabilizers. The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative. The requirements of this paragraph shall not apply to wind generators.

5.5 Equipment Procurement. If responsibility for construction of Transmission Provider's Interconnection Facilities or Network Upgrades is to be borne by Transmission Provider, then Transmission Provider shall commence design of Transmission Provider's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon

as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 Transmission Provider has completed the Facilities Study pursuant to the Facilities Study Agreement;

5.5.2 Transmission Provider has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.5.3 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.6 **Construction Commencement.** Transmission Provider shall commence construction of Transmission Provider's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Provider's Interconnection Facilities and Network Upgrades;

5.6.3 Transmission Provider has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.6.4 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.7 **Work Progress.** The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Either Party may, at any time, request a progress report from the other Party. If, at any time, Interconnection Customer determines that the completion of Transmission Provider's Interconnection Facilities will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider of such later date upon which the completion of Transmission Provider's Interconnection Facilities will be required.

5.8 **Information Exchange.** As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with Transmission Provider's Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Limited Operation. If any Transmission Provider's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and Interconnection Customer's Interconnection Facilities may operate prior to the completion of Transmission Provider's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. Transmission Provider shall permit Interconnection Customer to operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.10 Interconnection Customer's Interconnection Facilities ('ICIF'). Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.10.1 Interconnection Customer's Interconnection Facility Specifications. Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Provider at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Provider shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Transmission Provider's Review. Transmission Provider's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Provider, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Provider.

5.10.3 ICIF Construction. The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan

showing the Large Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Large Generating Facility. The Interconnection Customer shall provide Transmission Provider specifications for the excitation system, automatic voltage regulator, Large Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 Transmission Provider's Interconnection Facilities Construction. Transmission Provider's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Provider shall deliver to Interconnection Customer "as-built" drawings, information and documents for Transmission Provider's Interconnection Facilities.

Transmission Provider will obtain control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

5.12 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Provider or Transmission Owner, Transmission Provider or Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law,

to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 Permits. Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities. Interconnection Customer may request Transmission Provider to construct, and Transmission Provider shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Suspension. Interconnection Customer reserves the right, upon written notice to Transmission Provider, to suspend at any time all work by Transmission Provider associated with the construction and installation of Transmission Provider's Interconnection Facilities and/or Network Upgrades required under this LGIA with the condition that Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Provider's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Provider (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Provider cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Provider shall obtain Interconnection Customer's authorization to do so.

Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Transmission Provider required under this LGIA pursuant to this Article 5.16, and has not requested Transmission Provider to recommence the work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The

three-year period shall begin on the date the suspension is requested, or the date of the written notice to Transmission Provider, if no effective date is specified.

5.17 Taxes.

5.17.1 Interconnection Customer Payments Not Taxable. The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Provider for the installation of Transmission Provider's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 Representations and Covenants. In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to Transmission Provider for Transmission Provider's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of Transmission Provider's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Transmission Provider's request, Interconnection Customer shall provide Transmission Provider with a report from an independent engineer confirming its representation in clause (iii), above. Transmission Provider represents and covenants that the cost of Transmission Provider's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Transmission Provider. Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Transmission Provider from the cost consequences of any current tax liability imposed against Transmission Provider as the result of payments or property transfers made by Interconnection Customer to

Transmission Provider under this LGIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Provider.

Transmission Provider shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this LGIA unless (i) Transmission Provider has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Provider should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Provider to report payments or property as income subject to taxation; provided, however, that Transmission Provider may require Interconnection Customer to provide security for Interconnection Facilities, in a form reasonably acceptable to Transmission Provider (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Transmission Provider for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Provider of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by Transmission Provider upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 Tax Gross-Up Amount. Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Interconnection Customer will pay Transmission Provider, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on Transmission Provider ("Current Taxes") on the excess of (a) the gross income realized by Transmission Provider as a result of payments or property transfers made by Interconnection Customer to Transmission Provider under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Provider to receive and retain, after the payment of all Current Taxes, an amount equal to the

net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Provider's composite federal and state tax rates at the time the payments or property transfers are received and Transmission Provider will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Transmission Provider's anticipated tax depreciation deductions as a result of such payments or property transfers by Transmission Provider's current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 **Private Letter Ruling or Change or Clarification of Law.** At Interconnection Customer's request and expense, Transmission Provider shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission Provider under this LGIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Transmission Provider and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Provider shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Provider shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 **Subsequent Taxable Events.** If, within 10 years from the date on which the relevant Transmission Provider's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88129, or (iii) this LGIA terminates and Transmission Provider retains ownership of the Interconnection Facilities and Network

Upgrades, Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Transmission Provider, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 **Contests.** In the event any Governmental Authority determines that Transmission Provider's receipt of payments or property constitutes income that is subject to taxation, Transmission Provider shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Provider may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Provider reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Provider shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Provider may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Transmission Provider, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Transmission Provider for the tax at issue in the contest.

5.17.8 **Refund.** In the event that (a) a private letter ruling is issued to

Transmission Provider which holds that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Provider in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Provider under the terms of this LGIA is not taxable to Transmission Provider, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Provider are not subject to federal income tax, or (d) if Transmission Provider receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Provider pursuant to this LGIA, Transmission Provider shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by Interconnection Customer to Transmission Provider for such taxes which Transmission Provider did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission Provider refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Provider, any refund or credit Transmission Provider receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission Provider for such overpayment of taxes (including any reduction in interest otherwise payable by Transmission Provider to any Governmental Authority resulting from an offset or credit); provided, however, that Transmission Provider will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Provider has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to Transmission Provider's Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same

position they would have been in had no such tax payments been made.

5.17.9 Taxes Other Than Income Taxes. Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Transmission Provider may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Provider for which Interconnection Customer may be required to reimburse Transmission Provider under the terms of this LGIA. Interconnection Customer shall pay to Transmission Provider on a periodic basis, as invoiced by Transmission Provider, Transmission Provider's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Provider shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Provider for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Provider.

5.17.10 Transmission Owners Who Are Not Transmission Providers. If Transmission Provider is not the same entity as the Transmission Owner, then (i) all references in this Article 5.17 to Transmission Provider shall be deemed also to refer to and to include the Transmission Owner, as appropriate, and (ii) this LGIA shall not become effective until such Transmission Owner shall have agreed in writing to assume all of the duties and obligations of Transmission Provider under this Article 5.17 of this LGIA.

5.18 Tax Status. Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this LGIA is intended to adversely affect any Transmission Provider's tax exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. Either Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, that Party shall provide to the other Party sufficient information regarding such modification so that the other Party may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be

confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Large Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Provider shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Provider's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 **Standards.** Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 **Modification Costs**. Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Provider makes to Transmission Provider's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Provider's Interconnection Facilities or the Transmission System, or to provide transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

Article 6. Testing and Inspection

6.1 **Pre-Commercial Operation Date Testing and Modifications.** Prior to the Commercial Operation Date, Transmission Provider shall test Transmission Provider's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Large Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Large Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 Right to Observe Testing. Each Party shall notify the other Party in advance of its performance of tests of its Interconnection Facilities. The other Party has the right, at its own expense, to observe such testing.

6.4 Right to Inspect. Each Party shall have the right, but shall have no obligation to: (i) observe the other Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of the other Party's System Protection Facilities and other protective equipment; and (iii) review the other Party's maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this LGIA.

Article 7. Metering

7.1 General. Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Provider shall install Metering Equipment at the Point of Interconnection prior to any operation of the Large Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Large Generating Facility shall be measured at or, at Transmission Provider's option, compensated to, the Point of Interconnection. Transmission Provider shall provide metering quantities, in analog and/or digital form, to Interconnection Customer upon request. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 Check Meters. Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Provider's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Provider or its designee. The installation, operation and maintenance thereof shall be performed

entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 **Standards.** Transmission Provider shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

7.4 **Testing of Metering Equipment.** Transmission Provider shall inspect and test all Transmission Provider-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Provider shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than every two (2) years. Transmission Provider shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Provider's failure to maintain, then Transmission Provider shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission Provider shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

7.5 **Metering Data.** At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Provider and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection.

Article 8. Communications

8.1 **Interconnection Customer Obligations.** Interconnection Customer shall maintain satisfactory operating communications with Transmission Provider's Transmission System dispatcher or representative designated by Transmission Provider. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Large Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Provider as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Large Generating Facility to the location(s) specified by Transmission Provider. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or

separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 Remote Terminal Unit. Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Provider at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Provider through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Provider. Instantaneous bidirectional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Provider.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 No Annexation. Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4. Provision of Data from a Variable Energy Resource. The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. The Interconnection Customer with a Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility is a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in

maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

Article 9. Operations

9.1 General. Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 Control Area Notification. At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider in writing of the Control Area in which the Large Generating Facility will be located. If Interconnection Customer elects to locate the Large Generating Facility in a Control Area other than the Control Area in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area.

9.3 Transmission Provider Obligations. Transmission Provider shall cause the Transmission System and Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA. Transmission Provider may provide operating instructions to Interconnection Customer consistent with this LGIA and Transmission Provider's operating protocols and procedures as they may change from time to time. Transmission Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA. Interconnection Customer shall operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this LGIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Either Party may request that the other Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this LGIA.

9.5 Start-Up and Synchronization. Consistent with the Parties' mutually acceptable procedures, Interconnection Customer is responsible for the proper synchronization of the Large Generating Facility to Transmission Provider's Transmission System.

9.6 Reactive Power and Primary Frequency Response

9.6.1 Power Factor Design Criteria.

9.6.1.1 **Synchronous Generation.** Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all synchronous generators in the Control Area on a comparable basis**.**

9.6.1.2 **Non-Synchronous Generation.** Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation, at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the Control Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

9.6.2 **Voltage Schedules.** Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Transmission Provider shall require Interconnection Customer to operate the Large Generating Facility to produce or absorb reactive power within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Provider's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Provider shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Large Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the System Operator.

9.6.2.1 **Voltage Regulators.** Whenever the Large Generating Facility is operated in parallel with the Transmission System and voltage regulators are capable of operation, Interconnection Customer shall operate the Large Generating Facility with its voltage regulators in automatic operation. If the Large Generating Facility's voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Large Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Control Area on a comparable basis.

9.6.3 **Payment for Reactive Power.** Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.

9.6.4 **Primary Frequency Response.** Interconnection Customer shall ensure the primary frequency response capability of its Large Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Large Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate

capacity of the Large Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Large Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Large Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Large Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Interconnection Customer shall operate the Large Generating Facility consistent with the provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Large Generating Facilities.

9.6.4.1 **Governor or Equivalent Controls.** Whenever the Large Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Large Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Large Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls

will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Large Generating Facility's governor or equivalent controls to a minimum whenever the Large Generating Facility is operated in parallel with the Transmission System.

9.6.4.2 **Timely and Sustained Response.** Interconnection Customer shall ensure that the Large Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Large Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Large Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

9.6.4.3 **Exemptions.** Large Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement. Large Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 9.6.4, but shall be otherwise exempt from the operating requirements in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this Agreement.

9.6.4.4 **Electric Storage Resources.** Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Appendix C of its LGIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide

primary frequency response consistent with the conditions set forth in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.3 of this Agreement. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 9.6.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 **Outage Authority and Coordination.** Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency

Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to the Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

9.7.1.2 **Outage Schedules.** Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Large Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 **Outage Restoration.** If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects the other Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Party, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.7.2 **Interruption of Service.** If required by Good Utility Practice to do so, Transmission Provider may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's ability to perform such activities as are necessary

to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Provider;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Large Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 **Under-Frequency and Over Frequency Conditions.** The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the Transmission System. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to

and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

9.7.4 System Protection and Other Control Requirements

9.7.4.1 **System Protection Facilities.** Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Provider's Interconnection Facilities or the Transmission System as a result of the interconnection of the Large Generating Facility and Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 **Requirements for Protection.** In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit

breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Provider's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Large Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Large Generating Facility.

9.7.6 Power Quality. Neither Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

9.8 Switching and Tagging Rules. Each Party shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Provider's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection

Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or Transmission Provider's Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

Article 10. Maintenance

10.1 Transmission Provider Obligations. Transmission Provider shall maintain the Transmission System and Transmission Provider's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.2 Interconnection Customer Obligations. Interconnection Customer shall maintain the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.3 Coordination. The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Large Generating Facility and the Interconnection Facilities.

10.4 Secondary Systems. Each Party shall cooperate with the other in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Party. Each Party shall provide advance notice to the other Party before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

10.5 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1)

owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Provider's Interconnection Facilities.

Article 11. Performance Obligation

11.1 Interconnection Customer Interconnection Facilities. Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

11.2 Transmission Provider's Interconnection Facilities. Transmission Provider or Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Provider's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades. Transmission Provider or Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades. The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless Transmission Provider or Transmission Owner elects to fund the capital for the Network Upgrades, they shall be solely funded by Interconnection Customer.

11.4 Transmission Credits

11.4.1 Repayment of Amounts Advanced for Network Upgrades. Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, including any tax gross-up or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection Customer pursuant to Article 5.17.8 or otherwise, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Large Generating Facility. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider, and Affected System Operator may adopt any alternative

payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five years from the Commercial Operation Date: (1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or (2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond twenty (20) years from the Commercial Operation Date.

If the Large Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, Transmission Provider and Affected System Operator shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which reimbursement must be made.

11.4.2 **Special Provisions for Affected Systems.** Unless Transmission Provider provides, under the LGIA, for the repayment of amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

11.4.3 Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Large Generating Facility.

11.5 **Provision of Security.** At least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of a Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security

that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment shall be in an amount sufficient to cover the costs for constructing, procuring and installing the applicable portion of Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Provider for these purposes.

In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.6 Interconnection Customer Compensation. If Transmission Provider requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this LGIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to an RTO or ISO FERC-approved rate schedule. Interconnection Customer shall serve Transmission Provider or RTO or ISO with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this LGIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

11.6.1 **Interconnection Customer Compensation for Actions During Emergency Condition.** Transmission Provider or RTO or ISO shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.6.

Article 12. Invoice

12.1 General. Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the

invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice. Within six months after completion of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades, Transmission Provider shall provide an invoice of the final cost of the construction of Transmission Provider's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this LGIA.

12.4 Disputes. In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide Interconnection Service under this LGIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

Article 13. Emergencies

13.1 Definition. "Emergency Condition" shall mean a condition or situation: (i) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (ii) that, in the case of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, Transmission Provider's Interconnection Facilities or the Transmission Systems of others to which the Transmission System is directly connected; or (iii) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Large Generating Facility or Interconnection Customer's

Interconnection Facilities' System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by this LGIA to possess black start capability.

13.2 Obligations. Each Party shall comply with the Emergency Condition procedures of the applicable ISO/RTO, NERC, the Applicable Reliability Council, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

13.3 Notice. Transmission Provider shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Provider's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Provider's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Provider's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

13.4 Immediate Action. Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Provider, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or otherwise regarding the Transmission System.

13.5 Transmission Provider Authority.

13.5.1 General. Transmission Provider may take whatever actions or inactions with regard to the Transmission System or Transmission Provider's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Provider's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions

necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 **Reduction and Disconnection.** Transmission Provider may reduce Interconnection Service or disconnect the Large Generating Facility or Interconnection Customer's Interconnection Facilities, when such, reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to Transmission Provider's Tariff. When Transmission Provider can schedule the reduction or disconnection in advance, Transmission Provider shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer and Transmission Provider. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.6 **Interconnection Customer Authority.** Consistent with Good Utility Practice and the LGIA and the LGIP, Interconnection Customer may take actions or inactions with regard to the Large Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Provider's Interconnection Facilities. Transmission Provider shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 **Limited Liability.** Except as otherwise provided in Article 11.6.1 of this LGIA, neither

Party shall be liable to the other for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

Article 14. Regulatory Requirements and Governing Law

14.1 Regulatory Requirements. Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

Article 15. Notices.

15.1 General. Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Either Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given

by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Party in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

Article 16. Force Majeure

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

Article 17. Default

17.1 Default

17.1.1 **General.** No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act of omission of the other Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the

Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 **Right to Terminate.** If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this LGIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this LGIA.

Article 18. Indemnity, Consequential Damages and Insurance

18.1 **Indemnity.** The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this LGIA on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

18.1.1 **Indemnified Person.** If an Indemnified Person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the Indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such Indemnified Person may at the expense of the Indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 **Indemnifying Party.** If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this Article 18, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

18.1.3 **Indemnity Procedures.** Promptly after receipt by an Indemnified Person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably

satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the Indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be reasonably withheld, conditioned or delayed.

18.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 Insurance. Each party shall, at its own expense, maintain in force throughout the period of this LGIA, and until released by the other Party, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile

Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

Article 19. Assignment

19.1 Assignment. This LGIA may be assigned by either Party only with the written consent of the other; provided that either Party may assign this LGIA without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA; and provided further that Interconnection Customer shall have the right to assign this LGIA, without the consent of Transmission Provider, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that Interconnection Customer will promptly notify Transmission

Provider of any such assignment. Any financing arrangement entered into by Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

Article 20. Severability

20.1 Severability. If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Provider) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

Article 21. Comparability

21.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

Article 22. Confidentiality

22.1 Confidentiality. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 **Term.** During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 **Scope.** Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of the LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.1.3 **Release of Confidential Information.** Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 **Rights.** Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 **No Warranties.** By providing Confidential Information, neither Party

makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 **Standard of Care.** Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this LGIA or its regulatory requirements.

22.1.7 **Order of Disclosure.** If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 **Termination of Agreement.** Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 **Remedies.** The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are

necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 **Disclosure to FERC, its Staff, or a State.** Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this LGIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this LGIA ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other

reasonable measures.

Article 23. Environmental Releases

23.1 Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

Article 24. Information Requirements

24.1 **Information Acquisition.** Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 **Information Submission by Transmission Provider.** The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 **Updated Information Submission by Interconnection Customer.** The updated information submission by Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. Interconnection Customer shall submit a completed copy of the Large Generating Facility data requirements contained in Appendix 1 to the LGIP. It shall also include any additional information provided to Transmission Provider for the Feasibility and Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If Interconnection Customer's data is materially different from what was originally

provided to Transmission Provider pursuant to the Interconnection Study Agreement between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on Transmission Provider Transmission System based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 Information Supplementation. Prior to the Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Large Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to Transmission Provider for each individual generating unit in a station.

Subsequent to the Operation Date, Interconnection Customer shall provide Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Provider shall provide Interconnection Customer any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Provider-owned substation that may affect Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

Article 25. Information Access and Audit Rights

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is necessary in order for the other Party to: (i) verify the costs incurred by the disclosing Party for which the other Party is responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA.

25.2 Reporting of Non-Force Majeure Events. Each Party (the “notifying Party”) shall notify the other Party when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this LGIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this LGIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party, to audit at its own expense the other Party’s accounts and records pertaining to either Party’s performance or either Party’s satisfaction of obligations under this LGIA. Such audit rights shall include audits of the other Party’s costs, calculation of invoiced amounts, Transmission Provider’s efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider’s efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party’s actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party’s performance and satisfaction of obligations under this LGIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Transmission Provider’s Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Provider’s issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to either Party’s performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party’s receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

25.5 Audit Results. If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be

given to the other Party together with those records from the audit which support such determination.

Article 26. Subcontractors

26.1 General. Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

26.2 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Provider be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

Article 27. Disputes

27.1 Submission. In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 External Arbitration Procedures. Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial

business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail.

27.3 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 Costs. Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

Article 28. Representations, Warranties, and Covenants

28.1 General. Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 Authority. Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights

generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 **No Conflict.** The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 **Consent and Approval.** Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

Article 29. Joint Operating Committee

29.1 **Joint Operating Committee.** Except in the case of ISOs and RTOs, Transmission Provider shall constitute a Joint Operating Committee to coordinate operating and technical considerations of Interconnection Service. At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Interconnection Customer shall notify Transmission Provider of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of either Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this LGIA. Each Party shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

29.1.1 Establish data requirements and operating record requirements.

29.1.2 Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

29.1.3 Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Provider's and Interconnection Customer's facilities at the Point of Interconnection.

29.1.4 Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Large Generating Facility and other facilities that impact the normal operation of the interconnection of the

Large Generating Facility to the Transmission System.

29.1.5 Ensure that information is being provided by each Party regarding equipment availability.

29.1.6 Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

Article 30. Miscellaneous

30.1 Binding Effect. This LGIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts. In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation. This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix to this LGIA, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 Entire Agreement. This LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this LGIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this LGIA.

30.5 No Third Party Beneficiaries. This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 Waiver. The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this LGIA. Termination or Default of this LGIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 Headings. The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 Multiple Counterparts. This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment. The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by the Parties.

30.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. Transmission Provider shall have the right to make a unilateral filing with FERC to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

IN WITNESS WHEREOF, the Parties have executed this LGIA in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

Tri-State Generation and Transmission Association, Inc.

By: ______________________________________

Title: ______________________________________

Date: ______________________________________

[Insert name of Interconnection Customer]

By: ______________________________________

Title: ______________________________________

Date: ______________________________________

Appendix A to LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. Interconnection Facilities:

(a) [insert Interconnection Customer's Interconnection Facilities]:

(b) [insert Transmission Provider's Interconnection Facilities]:

2. Network Upgrades:

(a) [insert Stand Alone Network Upgrades]:

(b) [insert Other Network Upgrades]:

3. Distribution Upgrades:

Appendix B to LGIA

Milestones

Appendix C to LGIA

Interconnection Details

Appendix D to LGIA

Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

Appendix E to LGIA

Commercial Operation Date

This Appendix E is a part of the LGIA between Transmission Provider and Interconnection Customer.

[Date]

[Transmission Provider Address]

Re: _____________ Large Generating Facility

Dear _______________:

On **[Date] [Interconnection Customer]** has completed Trial Operation of Unit No. **___**. This letter confirms that [Interconnection Customer] commenced Commercial Operation of Unit No. **___** at the Large Generating Facility, effective as of **[Date plus one day]**.

Thank you.

[Signature]

[Interconnection Customer Representative]

Appendix F to LGIA

Addresses for Delivery of Notices and Billings

Notices:.

Transmission Provider:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

Billings and Payments:

Transmission Provider:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

APPENDIX G

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4-9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the

transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or "GSU"), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition

period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4-9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.
2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt

from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. <u>Power Factor Design Criteria (Reactive Power)</u>

The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a Facilities Study Agreement as of the effective date of the Final Rule establishing the reactive power requirements for non-synchronous generators in section 9.6.1 of this LGIA (Order No. 827). A wind generating plant to which this provision applies shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

iii. <u>Supervisory Control and Data Acquisition (SCADA) Capability</u>

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential

for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

APPENDIX 7

INTERCONNECTION PROCEDURES FOR A WIND GENERATING PLANT

Appendix 7 sets forth procedures specific to a wind generating plant. All other requirements of this LGIP continue to apply to wind generating plant interconnections.

A. Special Procedures Applicable to Wind Generators

The wind plant Interconnection Customer, in completing the Interconnection Request required by section 3.3 of this LGIP, may provide to the Transmission Provider a set of preliminary electrical design specifications depicting the wind plant as a single equivalent generator. Upon satisfying these and other applicable Interconnection Request conditions, the wind plant may enter the queue and receive the base case data as provided for in this LGIP.

No later than six months after submitting an Interconnection Request completed in this manner, the wind plant Interconnection Customer must submit completed detailed electrical design specifications and other data (including collector system layout data) needed to allow the Transmission Provider to complete the System Impact Study.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
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ATTACHMENT O

Small Generator Interconnection Procedures (SGIP)

(For Generating Facilities No Larger Than 20 MWs)
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Section 1. Application

1.1 Applicability

1.1.1 A request to interconnect a certified Small Generating Facility (See Attachments 3 and 4 for description of certification criteria) to the Transmission Provider's Distribution System shall be evaluated under the section 2 Fast Track Process if the eligibility requirements of section 2.1 are met. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kilowatts (kW) shall be evaluated under the Attachment 5 10 kW Inverter Process. A request to interconnect a Small Generating Facility no

larger than 20 megawatts (MW) that does not meet the eligibility requirements of section 2.1, or does not pass the Fast Track Process or the 10 kW Inverter Process, shall be evaluated under the section 3 Study Process. If the Interconnection Customer wishes to interconnect its Small Generating Facility using Network Resource Interconnection Service, it must do so under the Standard Large Generator Interconnection Procedures and execute the Standard Large Generator Interconnection Agreement.

1.1.2 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of these procedures.

1.1.3 Neither these procedures nor the requirements included hereunder apply to Small Generating Facilities interconnected or approved for interconnection prior to 60 Business Days after the effective date of these procedures.

1.1.4 Prior to submitting its Interconnection Request (Attachment 2), the Interconnection Customer may ask the Transmission Provider's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The Transmission Provider shall respond within 15 Business Days.

1.1.5 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Federal Energy Regulatory Commission expects all Transmission Providers, market participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

1.1.6 References in these procedures to interconnection agreement are to the Small Generator Interconnection Agreement (SGIA).

1.2 Pre-Application

1.2.1 The Transmission Provider shall designate an employee or office from which information on the application process and on an Affected System can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the Transmission Provider's Internet web site. Electric system information provided to the Interconnection Customer should include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Transmission Provider's Transmission System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The Transmission Provider shall comply with reasonable requests for such information.

1.2.2 In addition to the information described in section 1.2.1, which may be provided in response to an informal request, an Interconnection Customer may submit a formal written request form along with a non-refundable fee of $300 for a pre-application report on a proposed project at a specific site. The Transmission Provider shall provide the pre-application data described in section 1.2.3 to the Interconnection Customer within 20 Business Days of receipt of the completed request form and payment of the $300 fee. The pre-application report produced by the Transmission Provider is non-binding, does not confer any rights, and the Interconnection Customer must still successfully apply to interconnect to the Transmission Provider’s system. The written pre-application report request form shall include the information in sections 1.2.2.1 through 1.2.2.8 below to clearly and sufficiently identify the location of the proposed Point of Interconnection.

1.2.2.1 Project contact information, including name, address, phone number, and email address.

1.2.2.2 Project location (street address with nearby cross streets and town)

1.2.2.3 Meter number, pole number, or other equivalent information identifying proposed Point of Interconnection, if available.

1.2.2.4 Generator Type (e.g., solar, wind, combined heat and power, etc.)

1.2.2.5 Size (alternating current kW)

1.2.2.6 Single or three phase generator configuration

1.2.2.7 Stand-alone generator (no onsite load, not including station service – Yes or No?)

1.2.2.8 Is new service requested? Yes or No? If there is existing service, include the customer account number, site minimum and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.

1.2.3. Using the information provided in the pre-application report request form in section 1.2.2, the Transmission Provider will identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection. This selection by the Transmission Provider does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional pre-application reports if information about multiple Points of Interconnection is requested. Subject to section 1.2.4, the pre-application report will include the following information:

1.2.3.1 Total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Interconnection.

1.2.3.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Interconnection.

1.2.3.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of

generation in the queue) likely to serve the proposed Point of Interconnection.

1.2.3.4 Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Interconnection (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

1.2.3.5 Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

1.2.3.6 Nominal distribution circuit voltage at the proposed Point of Interconnection.

1.2.3.7 Approximate circuit distance between the proposed Point of Interconnection and the substation.

1.2.3.8 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in section 2.4.4.1.1 below and absolute minimum load, when available.

1.2.3.9 Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the substation/area. Identify whether the substation has a load tap changer.

1.2.3.10 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.

1.2.3.11 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.

1.2.3.12 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.

1.2.3.13 Based on the proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary

networks.

1.2.4 The pre-application report need only include existing data. A pre-application report request does not obligate the Transmission Provider to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the Transmission Provider cannot complete all or some of a pre-application report due to lack of available data, the Transmission Provider shall provide the Interconnection Customer with a pre-application report that includes the data that is available. The provision of information on "available capacity" pursuant to section 1.2.3.4 does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the pre-application report may become outdated at the time of the submission of the complete Interconnection Request. Notwithstanding any of the provisions of this section, the Transmission Provider shall, in good faith, include data in the pre-application report that represents the best available information at the time of reporting.

1.3 Interconnection Request

The Interconnection Customer shall submit its Interconnection Request to the Transmission Provider, together with the processing fee or deposit specified in the Interconnection Request. The Interconnection Request shall be date- and time-stamped upon receipt. The original date- and time-stamp applied to the Interconnection Request at the time of its original submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in these procedures. The Interconnection Customer shall be notified of receipt by the Transmission Provider within three Business Days of receiving the Interconnection Request. The Transmission Provider shall notify the Interconnection Customer within ten Business Days of the receipt of the Interconnection Request as to whether the Interconnection Request is complete or incomplete. If the Interconnection Request is incomplete, the

Transmission Provider shall provide along with the notice that the Interconnection Request is incomplete, a written list detailing all information that must be provided to complete the Interconnection Request. The Interconnection Customer will have ten Business Days after receipt of the notice to submit the listed information or to request an extension of time to provide such information. If the Interconnection Customer does not provide the listed information or a request for an extension of time within the deadline, the Interconnection Request will be deemed withdrawn. An Interconnection Request will be deemed complete upon submission of the listed information to the Transmission Provider.

1.4 Modification of the Interconnection Request

Any modification to machine data or equipment configuration or to the interconnection site of the Small Generating Facility not agreed to in writing by the Transmission Provider and the Interconnection Customer may be deemed a withdrawal of the Interconnection Request and may require submission of a new Interconnection Request, unless proper notification of each Party by the other and a reasonable time to cure the problems created by the changes are undertaken.

1.5 Site Control

Documentation of site control must be submitted with the Interconnection Request. Site control may be demonstrated through:

1.5.1 Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Small Generating Facility;

1.5.2 An option to purchase or acquire a leasehold site for such purpose; or

1.5.3 An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

1.6 Queue Position

The Transmission Provider shall assign a Queue Position based upon the date- and time-stamp of the Interconnection Request. The Queue Position of each Interconnection Request will be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. The Transmission Provider shall maintain a single queue per geographic region. At the Transmission Provider's option, Interconnection Requests may be studied serially or in clusters for the purpose of the system impact study.

1.7 Interconnection Requests Submitted Prior to the Effective Date of the SGIP

Nothing in this SGIP affects an Interconnection Customer's Queue Position assigned before the effective date of this SGIP. The Parties agree to complete work on any interconnection study agreement executed prior the effective date of this SGIP in accordance with the terms and conditions of that interconnection study agreement. Any new studies or other additional work will be completed pursuant to this SGIP.

Section 2. Fast Track Process

2.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission Provider's Distribution System if the Small Generating Facility’s capacity does not exceed the size limits identified in the table below. Small Generating Facilities below these limits are eligible for Fast Track review. However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a Small Generating Facility will pass the Fast Track screens in section 2.2.1 below or the Supplemental Review screens in section 2.4.1 below.

Fast Track eligibility is determined based upon the generator type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection. All Small Generating Facilities connecting to lines greater than 69 kilovolt (kV) are ineligible for the Fast Track

Process regardless of size. All synchronous and induction machines must be no larger than 2 MW to be eligible for the Fast Track Process, regardless of location. For certified inverter-based systems, the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based Small Generating Facilities located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds according to the table below. In addition to the size threshold, the Interconnection Customer's proposed Small Generating Facility must meet~~s~~ the codes, standards, and certification requirements of Attachments 3 and 4 of these procedures, or the Transmission Provider has to have reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline and ≤ 2.5 Electrical Circuit Miles from Substation
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

2.2 Initial Review

Within 15 Business Days after the Transmission Provider notifies the Interconnection Customer it has received a complete Interconnection Request, the Transmission Provider shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Transmission Provider's determinations under the screens.

2.2.1 Screens

2.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Transmission Provider's Distribution System that is subject to the Tariff.

2.2.1.2 For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Transmission Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

2.2.1.3 For interconnection of a proposed Small Generating

Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5 % of a spot network's maximum load or 50 kW.

2.2.1.4 The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

2.2.1.5 The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 % of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5 % of the short circuit interrupting capability.

2.2.1.6 Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Transmission Provider's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	**Type of Interconnection to Primary Distribution Line**	**Result/Criteria**
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass Screen

2.2.1.7 If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

2.2.1.8 If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20 % of the nameplate rating of the service transformer.

2.2.1.9 The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

2.2.1.10 No construction of facilities by the Transmission Provider on its own system shall be required to accommodate the Small Generating Facility.

2.2.2 If the proposed interconnection passes the screens, the Interconnection Request shall be approved and the Transmission Provider will provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.3 If the proposed interconnection fails the screens, but the Transmission Provider determines that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five

Business Days after the determination.

2.2.4 If the proposed interconnection fails the screens, and the Transmission Provider does not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Transmission Provider shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

2.3 Customer Options Meeting

If the Transmission Provider determines the Interconnection Request cannot be approved without (1) minor modifications at minimal cost, (2) a supplemental study or other additional studies or actions, or (3) incurring significant cost to address safety, reliability, or power quality problems, the Transmission Provider shall notify the Interconnection Customer of that determination within five Business Days after the determination and provide copies of all data and analyses underlying its conclusion. Within ten Business Days of the Transmission Provider's determination, the Transmission Provider shall offer to convene a customer options meeting with the Transmission Provider to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the Transmission Provider's determination, or at the customer options meeting, the Transmission Provider shall:

2.3.1 Offer to perform facility modifications or minor modifications to the Transmission Provider's electric system (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Transmission Provider's electric system. If the Interconnection Customer agrees to pay for the modifications to the Transmission Provider’s electric system, the Transmission Provider will provide the Interconnection Customer with an executable interconnection agreement within ten

Business Days of the customer options meeting; or

2.3.2 Offer to perform a supplemental review in accordance with section 2.4 and provide a non-binding good faith estimate of the costs of such review; or

2.3.3 Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under the section 3 Study Process.

2.4 Supplemental Review

2.4.1 To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing and submit a deposit for the estimated costs of the supplemental review in the amount of the Transmission Provider’s good faith estimate of the costs of such review, both within 15 Business Days of the offer. If the written agreement and deposit have not been received by the Transmission Provider within that timeframe, the Interconnection Request shall continue to be evaluated under the section 3 Study Process unless it is withdrawn by the Interconnection Customer.

2.4.2 The Interconnection Customer may specify the order in which the Transmission Provider will complete the screens in section 2.4.4.

2.4.3 The Interconnection Customer shall be responsible for the Transmission Provider's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 20 Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Transmission Provider will return such excess within 20 Business Days of the invoice without interest.

2.4.4 Within 30 Business Days following receipt of the deposit for a supplemental review, the Transmission Provider shall (1) perform a supplemental review using the screens set forth below; (2) notify in writing the Interconnection Customer of the results; and (3) include with the notification copies of the

analysis and data underlying the Transmission Provider's determinations under the screens. Unless the Interconnection Customer provided instructions for how to respond to the failure of any of the supplemental review screens below at the time the Interconnection Customer accepted the offer of supplemental review, the Transmission Provider shall notify the Interconnection Customer following the failure of any of the screens, or if it is unable to perform the screen in section 2.4.4.1, within two Business Days of making such determination to obtain the Interconnection Customer's permission to: (1) continue evaluating the proposed interconnection under this section 2.4.4; (2) terminate the supplemental review and continue evaluating the Small Generating Facility under section 3; or (3) terminate the supplemental review upon withdrawal of the Interconnection Request by the Interconnection Customer.

2.4.4.1 Minimum Load Screen: Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed Small Generating Facility) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Generating Facility capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed Small Generating Facility. If minimum load data is not available, or cannot be calculated, estimated or determined, the Transmission Provider shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under section 2.4.4.

2.4.4.1.1 The type of generation used by the proposed

Small Generating Facility will be taken into

account when calculating, estimating, or determining circuit or line section minimum load relevant for the application of screen 2.4.4.1.. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e. 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.

2.4. 4.1.2 When this screen is being applied to a Small Generating Facility that serves some station service load, only the net injection into the Transmission Provider’s electric system will be considered as part of the aggregate generation.

2.4. 4.1.3 Transmission Provider will not consider as part of the aggregate generation for purposes of this screen generating facility capacity known to be already reflected in the minimum load data.

2.4.4.2 Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

2.4.4.3 Safety and Reliability Screen: The location of the proposed Small Generating Facility and the aggregate generation capacity on the line section do not create

impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The Transmission Provider shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.

2.4.4.3.1 Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

2.4.4.3.2 Whether the loading along the line section is uniform or even.

2.4.4.3.3 Whether the proposed Small Generating Facility is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Interconnection is a Mainline rated for normal and emergency ampacity.

2.4.4.3.4 Whether the proposed Small Generating Facility incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

2.4.4.3.5 Whether operational flexibility is reduced by the proposed Small Generating Facility, such that transfer of the line section(s) of the Small Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

2.4.4.3.6 Whether the proposed Small Generating Facility employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

2.4.5 If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the Interconnection Request shall be approved and the Transmission Provider will provide the Interconnection Customer with an executable interconnection agreement within the timeframes established in sections 2.4.5.1 and 2.4.5.2 below. If the proposed interconnection fails any of the supplemental review screens and the Interconnection Customer does not withdraw its Interconnection Request, it shall continue to be evaluated under the section 3 Study Process consistent with section 2.4.5.3 below.

2.4.5.1 If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above and does not require construction of facilities by the Transmission Provider on its own system, the interconnection agreement shall be provided within ten Business Days after the notification of the supplemental review results.

2.4.5.2 If interconnection facilities or minor modifications to the Transmission Provider's system are required for the proposed interconnection to pass the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, and the Interconnection Customer agrees to pay for the modifications to the Transmission Provider’s electric system, the interconnection agreement, along with a non-binding good faith estimate for the interconnection facilities and/or minor modifications, shall be provided to the Interconnection Customer within 15 Business Days after receiving written notification of the supplemental

review results.

2.4.5.3 If the proposed interconnection would require more than interconnection facilities or minor modifications to the Transmission Provider's system to pass the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the Transmission Provider shall notify the Interconnection Customer, at the same time it notifies the Interconnection Customer with the supplemental review results, that the Interconnection Request shall be evaluated under the section 3 Study Process unless the Interconnection Customer withdraws its Small Generating Facility.

Section 3. Study Process

3.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission Provider's Transmission System or Distribution System if the Small Generating Facility (1) is larger than 2 MW but no larger than 20 MW, (2) is not certified, or (3) is certified but did not pass the Fast Track Process or the 10 kW Inverter Process.

3.2 Scoping Meeting

3.2.1 A scoping meeting will be held within ten Business Days after the Interconnection Request is deemed complete, or as otherwise mutually agreed to by the Parties. The Transmission Provider and the Interconnection Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting.

3.2.2 The purpose of the scoping meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request. The Parties shall further discuss whether the Transmission Provider should perform a feasibility study or proceed directly to a system impact study, or a facilities study, or an interconnection agreement. If the Parties agree that a feasibility study should be performed, the Transmission Provider shall provide the Interconnection Customer, as soon as possible, but not later than five Business Days after the scoping meeting, a feasibility study agreement (Attachment 6) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.2.3 The scoping meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an Interconnection Customer who has requested a feasibility study must return the executed feasibility study agreement within 15 Business Days. If the Parties agree not to perform a feasibility study, the Transmission Provider shall provide the Interconnection Customer, no later than five Business Days after the scoping meeting, a system impact study agreement (Attachment 7) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.3 <u>Feasibility Study</u>

3.3.1 The feasibility study shall identify any potential adverse system impacts that would result from the interconnection of the Small Generating Facility.

3.3.2 A deposit of the lesser of 50 percent of the good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

3.3.3 The scope of and cost responsibilities for the feasibility study are described in the attached feasibility study agreement (Attachment 6).

3.3.4 If the feasibility study shows no potential for adverse system impacts, the Transmission Provider shall send the Interconnection

Customer a facilities study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study. If no additional facilities are required, the Transmission Provider shall send the Interconnection Customer an executable interconnection agreement within five Business Days.

3.3.5 If the feasibility study shows the potential for adverse system impacts, the review process shall proceed to the appropriate system impact study(s).

3.4 System Impact Study

3.4.1 A system impact study shall identify and detail the electric system impacts that would result if the proposed Small Generating Facility were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the feasibility study, or to study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

3.4.2 If no transmission system impact study is required, but potential electric power Distribution System adverse system impacts are identified in the scoping meeting or shown in the feasibility study, a distribution system impact study must be performed. The Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement within 15 Business Days of transmittal of the feasibility study report, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or following the scoping meeting if no feasibility study is to be performed.

3.4.3 In instances where the feasibility study or the distribution system impact study shows potential for transmission system adverse system impacts, within five Business Days following transmittal of the feasibility study report, the Transmission Provider shall send the Interconnection Customer a transmission system impact study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, if

such a study is required.

3.4.4 If a transmission system impact study is not required, but electric power Distribution System adverse system impacts are shown by the feasibility study to be possible and no distribution system impact study has been conducted, the Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement.

3.4.5 If the feasibility study shows no potential for transmission system or Distribution System adverse system impacts, the Transmission Provider shall send the Interconnection Customer either a facilities study agreement (Attachment 8), including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or an executable interconnection agreement, as applicable.

3.4.6 In order to remain under consideration for interconnection, the Interconnection Customer must return executed system impact study agreements, if applicable, within 30 Business Days.

3.4.7 A deposit of the good faith estimated costs for each system impact study may be required from the Interconnection Customer.

3.4.8 The scope of and cost responsibilities for a system impact study are described in the attached system impact study agreement.

3.4.9 Where transmission systems and Distribution Systems have separate owners, such as is the case with transmission-dependent utilities ("TDUs") – whether investor-owned or not – the Interconnection Customer may apply to the nearest Transmission Provider (Transmission Owner, Regional Transmission Operator, or Independent Transmission Provider) providing transmission service to the TDU to request project coordination. Affected Systems shall participate in the study and provide all information necessary to prepare the study.

3.5 <u>Facilities Study</u>

3.5.1 Once the required system impact study(s) is completed, a system impact study report shall be prepared and transmitted to the

Interconnection Customer along with a facilities study agreement within five Business Days, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study. In the case where one or both impact studies are determined to be unnecessary, a notice of the fact shall be transmitted to the Interconnection Customer within the same timeframe.

3.5.2 In order to remain under consideration for interconnection, or, as appropriate, in the Transmission Provider's interconnection queue, the Interconnection Customer must return the executed facilities study agreement or a request for an extension of time within 30 Business Days.

3.5.3 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s).

3.5.4 Design for any required Interconnection Facilities and/or Upgrades shall be performed under the facilities study agreement. The Transmission Provider may contract with consultants to perform activities required under the facilities study agreement. The Interconnection Customer and the Transmission Provider may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the Transmission Provider, under the provisions of the facilities study agreement. If the Parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the Transmission Provider shall make sufficient information available to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

3.5.5 A deposit of the good faith estimated costs for the facilities study may be required from the Interconnection Customer.

3.5.6 The scope of and cost responsibilities for the facilities study are described in the attached facilities study agreement.

3.5.7 Upon completion of the facilities study, and with the agreement of the Interconnection Customer to pay for Interconnection Facilities and Upgrades identified in the facilities study, the Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five Business Days.

Section 4. Provisions that Apply to All Interconnection Requests

4.1 Reasonable Efforts

The Transmission Provider shall make reasonable efforts to meet all time frames provided in these procedures unless the Transmission Provider and the Interconnection Customer agree to a different schedule. If the Transmission Provider cannot meet a deadline provided herein, it shall notify the Interconnection Customer, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

4.2 Disputes

4.2.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

4.2.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

4.2.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

4.2.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at http://www.ferc.gov/legal/adr.asp.

4.2.5 Each Party agrees to conduct all negotiations in good faith and will

be responsible for one-half of any costs paid to neutral third-parties.

4.2.6 If neither Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

4.3 Interconnection Metering

Any metering necessitated by the use of the Small Generating Facility shall be installed at the Interconnection Customer's expense in accordance with Federal Energy Regulatory Commission, state, or local regulatory requirements or the Transmission Provider's specifications.

4.4 Commissioning

Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards. The Transmission Provider must be given at least five Business Days written notice, or as otherwise mutually agreed to by the Parties, of the tests and may be present to witness the commissioning tests.

4.5. Confidentiality

4.5.1 Confidential information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed confidential information regardless of whether it is clearly marked or otherwise designated as such.

4.5.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations

under these procedures, or to fulfill legal or regulatory requirements.

4.5.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

4.5.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

4.5.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to these procedures, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC. The Party shall notify the other Party when it is notified by FERC that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

4.6 Comparability

The Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this document. The Transmission Provider shall use the same reasonable efforts in processing and analyzing Interconnection Requests from all

Interconnection Customers, whether the Small Generating Facility is owned or operated by the Transmission Provider, its subsidiaries or affiliates, or others.

4.7 Record Retention

The Transmission Provider shall maintain for three years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

4.8 Interconnection Agreement

After receiving an interconnection agreement from the Transmission Provider, the Interconnection Customer shall have 30 Business Days or another mutually agreeable timeframe to sign and return the interconnection agreement or request that the Transmission Provider file an unexecuted interconnection agreement with the Federal Energy Regulatory Commission. If the Interconnection Customer does not sign the interconnection agreement, or ask that it be filed unexecuted by the Transmission Provider within 30 Business Days, the Interconnection Request shall be deemed withdrawn. After the interconnection agreement is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the interconnection agreement.

4.9 Coordination with Affected Systems

The Transmission Provider shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The Transmission Provider will include such Affected System operators in all meetings held with the Interconnection Customer as required by these procedures. The Interconnection Customer will cooperate with the Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider which may be an Affected System shall cooperate with the Transmission Provider with

whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

4.10 Capacity of the Small Generating Facility

4.10.1 If the Interconnection Request is for an increase in capacity for an existing Small Generating Facility, the Interconnection Request shall be evaluated on the basis of the new total capacity of the Small Generating Facility.

4.10.2 If the Interconnection Request is for a Small Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices.

4.10.3 The Interconnection Request shall be evaluated using the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system. However, if the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system is limited (e.g., through use of a control system, power relay(s), or other similar device settings or adjustments), then the Interconnection Customer must obtain the Transmission Provider's agreement, with such agreement not to be unreasonably withheld, that the manner in which the Interconnection Customer proposes to implement such a limit will not adversely affect the safety and reliability of the Transmission Provider's system. If the Transmission Provider does not so agree, then the Interconnection Request must be withdrawn or revised to specify the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system without such limitations. Furthermore, nothing in this section

shall prevent a Transmission Provider from considering an output higher than the limited output, if appropriate, when evaluating system protection impacts.

Attachment 1
Glossary of Terms

10 kW Inverter Process – The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the section 2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5.

Affected System – An electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Business Day – Monday through Friday, excluding Federal Holidays.

Distribution System – The Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Fast Track Process – The procedure for evaluating an Interconnection Request for a certified Small Generating Facility that meets the eligibility requirements of section 2.1 and includes the section 2 screens, customer options meeting, and optional supplemental review.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and act which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a

reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

Interconnection Customer – Any entity, including the Transmission Provider, the Transmission Owner or any of the affiliates or subsidiaries of either, that proposes to interconnect its Small Generating Facility with the Transmission Provider's Transmission System.

Interconnection Facilities – The Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Request – The Interconnection Customer's request, in accordance with the Tariff, to interconnect a new Small Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the Transmission Provider’s Transmission System.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Network Resource – Any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service – An Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission Provider’s System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management,

in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades – Additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Transmission Provider's Transmission System to accommodate the interconnection with the Small Generating Facility to the Transmission Provider's Transmission System. Network Upgrades do not include Distribution Upgrades.

Party or Parties – The Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Transmission Provider's Transmission System.

Queue Position – The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Small Generating Facility – The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Study Process – The procedure for evaluating an Interconnection Request that includes the section 3 scoping meeting, feasibility study, system impact study, and facilities study.

Transmission Owner – The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Small Generator Interconnection Agreement to the extent necessary.

Transmission Provider – The public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission System – The facilities owned, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service under the Tariff.

Upgrades – The required additions and modifications to the Transmission Provider's Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Attachment 2
SMALL GENERATOR INTERCONNECTION REQUEST
(Application Form)

Transmission Provider:

____

Designated Contact Person:

____

Address:

____

Telephone Number:

____

Fax: ____

E-Mail Address:

____

An Interconnection Request is considered complete when it provides all applicable and correct information required below. Per SGIP section 1.5, documentation of site control must be submitted with the Interconnection Request.

Preamble and Instructions

An Interconnection Customer who requests a Federal Energy Regulatory Commission jurisdictional interconnection must submit this Interconnection Request by hand delivery, mail, e-mail, or fax to the Transmission Provider.

Processing Fee or Deposit:

If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is $500.

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the Transmission Provider a deposit not to exceed $1,000 towards the cost of the feasibility study.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name:

____

Contact Person:

____

Mailing Address:

____

City: _____________________________ State:________________
Zip:_____________

Facility Location (if different from above):____

____

Telephone (Day): _____________________ Telephone (Evening):

____

Fax:____________________ E-Mail Address:

____

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name:

____

Title:

____

Address:____

____

Telephone (Day): ___________________ Telephone (Evening):____________________

Fax: _______________________ E-Mail Address: ________________________

Application is for: ______New Small Generating Facility

______Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe:

____

____

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ___ No ___

To Supply Power to the Interconnection Customer? Yes ___No ___

To Supply Power to Others? Yes ____ No ____

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

____

(Local Electric Service Provider*) (Existing Account Number*)

[*To be provided by the Interconnection Customer if the local electric service provider is different from the Transmission Provider]

Contact Name:

____

Title:

____

Address:

____

____

Telephone (Day): __________________Telephone (Evening): ________________

Fax: ___________________________ E-Mail Address:

Requested Point of Interconnection:

____

____

Interconnection Customer's Requested In-Service Date:

____

Small Generating Facility Information

Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___Solar ___Wind ___Hydro ___ Hydro Type (e.g. Run-of-River):__________ __Diesel __ Natural Gas __ Fuel Oil Other (state type) _____________________________

Prime Mover: __Fuel Cell __Recip Engine __Gas Turb __Steam Turb __Microturbine __PV __Other

Type of Generator: ____Synchronous ____Induction ____ Inverter

Generator Nameplate Rating: ________kW (Typical) Generator Nameplate kVAR: _______

Interconnection Customer or Customer-Site Load: _________________kW (if none, so state)

Typical Reactive Load (if known): _________________

Primary Frequency response operating range for electric storage resources:

____

Minimum State of Charge: __________

Maximum State of Charge: __________

Maximum Physical Export Capability Requested: ______________ kW

List components of the Small Generating Facility equipment package that are currently certified:

	Equipment Type	Certifying Entity
1.		______________________________

____________________________ _
____
2. ___________________________________
____________________________ _
____
3. ___________________________________
____________________________ _
____
4. ___________________________________
____________________________ _
____
5. ___________________________________
____________________________ _
____

Is the prime mover compatible with the certified protective relay package?
_____Yes _____No

Generator (or solar collector) Manufacturer, Model Name & Number:
____

Version Number: ______________________

Nameplate Output Power Rating in kW: (Summer) ________________ (Winter)
____

Nameplate Output Power Rating in kVA: (Summer) ________________ (Winter)
____

Individual Generator Power Factor

Rated Power Factor: Leading: ________________Lagging: __________________

Total Number of Generators in wind farm to be interconnected pursuant to this

Interconnection Request: ____________ Elevation:______ ____Single phase
____Three phase

Inverter Manufacturer, Model Name & Number (if

used):________________________________

List of adjustable set points for the protective equipment or software: ______________________

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: _______ Instantaneous or RMS_______?
Harmonics Characteristics: ____
Start-up requirements: ____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____________

(*) Neutral Grounding Resistor (If Applicable): ____________

Synchronous Generators:
Direct Axis Synchronous Reactance, X_d: _______ P.U.
Direct Axis Transient Reactance, X'_d: ___________P.U.
Direct Axis Subtransient Reactance, X''_d: ______________P.U.
Negative Sequence Reactance, X_2: _________ P.U.
Zero Sequence Reactance, X_0: ____________ P.U.

KVA Base: _______________
Field Volts: _______________
Field Amperes: ____________

Induction Generators:
Motoring Power (kW): ______________
I22t or K (Heating Time Constant): ______________
Rotor Resistance, Rr: ______________
Stator Resistance, Rs: ______________
Stator Reactance, Xs: ______________

Rotor Reactance, Xr: _______________
Magnetizing Reactance, Xm: _______________
Short Circuit Reactance, Xd'': _______________
Exciting Current: _______________
Temperature Rise: _______________
Frame Size: _______________
Design Letter: _______________
Reactive Power Required In Vars (No Load): _______________
Reactive Power Required In Vars (Full Load): _______________
Total Rotating Inertia, H: ______________ Per Unit on kVA Base

Note: Please contact the Transmission Provider prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only
Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling?
__Yes __No
Will the transformer be provided by the Interconnection Customer? ____Yes ____No

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):
Is the transformer: ____single phase _____three phase?
Size: ____________kVA
Transformer Impedance: _______% on __________kVA Base
If Three Phase:
Transformer Primary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Secondary: _____ Volts _____ Delta _____Wye _____ Wye

Grounded
Transformer Tertiary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: ___________________ Type: ________________ Size: _______ Speed: __________

Interconnecting Circuit Breaker (if applicable):

Manufacturer: ______________________________ Type: ___________

Load Rating (Amps): ______ Interrupting Rating (Amps): _______ Trip Speed (Cycles): _______

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.	________________________	________	________
2.	________________________	________	________
3.	________________________	________	________
4.	________________________	________	________
5.	________________________	________	________
6.	________________________	________	________

If Discrete Components:
(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer:______________	Type:____	Style/Catalog No.:_____	Proposed Setting:______
Manufacturer:______________	Type:____	Style/Catalog No.:_____	Proposed Setting:______
Manufacturer:______________	Type:____	Style/Catalog No.:_____	Proposed Setting:______

Manufacturer:_______________ Type:_____ Style/Catalog No.:______ Proposed Setting:_______

Manufacturer:_______________ Type:_____ Style/Catalog No.:______ Proposed Setting:_______

Current Transformer Data (If Applicable):
(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer:
____

Type: _______________________ Accuracy Class: ______ Proposed Ratio Connection: __________

Manufacturer:
____

Type: _______________________ Accuracy Class: ______ Proposed Ratio Connection: __________

Potential Transformer Data (If Applicable):

Manufacturer:
____

Type: _______________________ Accuracy Class: ______ Proposed Ratio Connection: __________

Manufacturer:
____

Type: _______________________ Accuracy Class: ______ Proposed Ratio Connection: __________

General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generating Facility is larger than 50 kW. Is One-Line Diagram Enclosed? ____Yes ____No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address)____

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ___Yes ____No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).
Are Schematic Drawings Enclosed? ___Yes ____No

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer: ____________________________________

Date: ___________

Attachment 3

Certification Codes and Standards

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of

Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms

NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Attachment 4
Certification of Small Generator Equipment Packages

1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards

referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Attachment 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

6.0 An equipment package does not include equipment provided by the utility.

7.0 Any equipment package approved and listed in a state by that state's

regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection procedures shall be considered certified under these procedures for use in that state.

Attachment 5
Application, Procedures, and Terms and Conditions for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10 kW ("10 kW Inverter Process")

1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the Transmission Provider ("Company").

2.0 The Company acknowledges to the Customer receipt of the Application within three Business Days of receipt.

3.0 The Company evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.

4.0 The Company verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in the Small Generator Interconnection Procedures (SGIP). The Company has 15 Business Days to complete this process. Unless the Company determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the Company approves the Application and returns it to the Customer. Note to Customer: Please check with the Company before submitting the Application if disconnection equipment is required.

5.0 After installation, the Customer returns the Certificate of Completion to the Company. Prior to parallel operation, the Company may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary.

6.0 The Company notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not

satisfactory, the Company has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Company is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion. If the Company does not inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

7.0 Contact Information – The Customer must provide the contact information for the legal applicant (i.e., the Interconnection Customer). If another entity is responsible for interfacing with the Company, that contact information must be provided on the Application.

8.0 Ownership Information – Enter the legal names of the owner(s) of the Small Generating Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.

9.0 UL1741 Listed – This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

Application for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10kW

This Application is considered complete when it provides all applicable and correct information required below. Per SGIP section 1.5, documentation of site control must be submitted with the Interconnection Request. Additional information to evaluate the Application may be required.

Processing Fee

A non-refundable processing fee of $100 must accompany this Application.

Interconnection Customer

Name:

____

Contact Person:

____

Address:

____

City: ______________________________ State: ______ Zip: __________

Telephone (Day): ________________ (Evening): ________________

Fax: ________________ E-Mail Address: ________________

Contact (if different from Interconnection Customer)

Name:

____

Contact Person:

____

Address:

____

City: ______________________________ State: ______ Zip: __________

Telephone (Day): ________________ (Evening): ________________

Fax: ________________ E-Mail Address: ________________

Owner of the facility (include % ownership by any electric utility):

____

____

Small Generating Facility Information

Location (if different from above):

____

Electric Service Company:

____

Account Number:

____

Inverter Manufacturer: _______________________ Model: ____________________
Nameplate Rating:_____(kW) _____(kVA) _____(AC Volts)

Single Phase ____ Three Phase____

System Design Capacity: _________ (kW) _______ (kVA)

Prime Mover: ___Photovoltaic ___Reciprocating Engine ___Fuel Cell

___Turbine ___Other (describe)_____________________

Energy Source: ___Solar ___Wind ___Hydro ___Diesel ___Natural Gas

___Fuel Oil ___Other (describe) _________________________

Is the equipment UL1741 Listed? ___Yes ___No

If Yes, attach manufacturer's cut-sheet showing UL1741 listing
Estimated Installation Date: ____________ Estimated In-Service Date: ________

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the Small Generator Interconnection Procedures (SGIP), or the Transmission Provider has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

	Equipment Type	Certifying Entity
1.	____________________	________________
2.	____________________	________________
3.	____________________	________________
4.	____________________	________________
5.	____________________	________________

Interconnection Customer Signature

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed:

____

Title: ______________________ Date: __________________________

Contingent Approval to Interconnect the Small Generating Facility

(For Company use only)

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Company Signature:

____

Title: ______________________ Date: __________________________

Application ID number: _________________

Company waives inspection/witness test? Yes___ No___

Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes______ No ______

Interconnection Customer:

____

Contact Person:

____

Address:

____

Location of the Small Generating Facility (if different from above):

____

_________________________________ City: ______________________________

State: ______ Zip: __________

Telephone (Day): ________________ (Evening): ________________

Fax: ________________ E-Mail Address: ________________

Electrician:

Name:

____

Address: ____

Location of the Small Generating Facility (if different from above):

____

_________________________________ City: ______________________________

State: ______ Zip: __________

Telephone (Day): ________________ (Evening): ________________

Fax: ________________ E-Mail Address: ________________

License number: ______________________________________

Date Approval to Install Facility granted by the Company:

____

Application ID number: ________________________________

Inspection:
The Small Generating Facility has been installed and inspected in compliance with the local
building/electrical code of:

____

Signed (Local electrical wiring inspector, or attach signed electrical inspection):
____

Print Name: ___________________________

Date: _________________________________

As a condition of interconnection, you are required to send/fax a copy of this form along with a copy of the signed electrical permit to (insert Company information below):

Name: ____

Company: ____

Address:____

____

City, State ZIP: ____________________________________

Fax: ____

……………………………………………………………………………………………
………

Approval to Energize the Small Generating Facility (For Company use only)

Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

Company Signature:

____

Title: ___________________________ Date: _________________

Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

1.0 Construction of the Facility

The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the Transmission Provider (the "Company") approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 Interconnection and Operation

The Customer may operate Small Generating Facility and interconnect with the Company's electric system once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the Company, and

2.3 The Company has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Company, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Company shall provide a written statement that the Small Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Company does not schedule an inspection of the Small Generating Facility within ten business days after receiving the

Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Company waives the right to inspect the Small Generating Facility.

2.4 The Company has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

3.0 Safe Operations and Maintenance

The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

4.0 Access

The Company shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Company shall provide reasonable notice to the Customer when possible prior to using its right of access.

5.0 Disconnection

The Company may temporarily disconnect the Small Generating Facility upon the following conditions:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Small Generating Facility does not operate in the manner consistent with these Terms and Conditions.

5.4 The Company shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 Indemnification

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting

from the other Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7. 0 Insurance

The Parties agree to follow all applicable insurance requirements imposed by the state in which the Point of Interconnection is located. All insurance policies must be maintained with insurers authorized to do business in that state.

8.0 Limitation of Liability

Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0.

9.0 Termination

The agreement to operate in parallel may be terminated under the following conditions:

9.1 **By the Customer**

By providing written notice to the Company.

9.2 **By the Company**

If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.

9.3 **Permanent Disconnection**

In the event this Agreement is terminated, the Company shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.

9.4 **Survival Rights**

This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

10.0 Assignment/Transfer of Ownership of the Facility
This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the Company.

Attachment 6
Feasibility Study Agreement

THIS AGREEMENT is made and entered into this _____day of _______________

20___ by and between____,

a ______________________________organized and existing under the laws of the State of

____, ("Interconnection Customer,") and

____,

a_________________

existing under the laws of the State of____,

("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on___________________________; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System; and

WHEREAS, Interconnection Customer has requested the Transmission Provider to perform a feasibility study to assess the feasibility of interconnecting the proposed Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed an interconnection feasibility study consistent the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.

5.0 In performing the study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6.0 The feasibility study report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

6.3 Initial review of grounding requirements and electric system protection; and

6.4 Description and non-binding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9.0 A deposit of the lesser of 50 percent of good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a feasibility study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 Governing Law, Regulatory Authority, and Rules
The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of ___________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

14.0 Amendment
The Parties may amend this Agreement by a written instrument duly executed by both Parties.

15.0 No Third-Party Beneficiaries
This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

16.0 Waiver

16.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

16.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts
This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

19.0 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

20.0 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

20.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider] [Insert name of Interconnection Customer]

______________________________ ________________________________

Signed: ______________________ Signed: _________________________

Name (Printed): Name (Printed):

_____________________________ __________________________________

Title: ________________________ Title: ____________________________

Attachment A to
Feasibility Study Agreement

Assumptions Used in Conducting the Feasibility Study

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on _____________________:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Attachment 7
System Impact Study Agreement

THIS AGREEMENT is made and entered into this _____day of______________ 20___ by and between____,

a___________________________ organized and existing under the laws of the State of

____, ("Interconnection Customer,") and

____,
a_________________

existing under the laws of the State
of____,

("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on__________________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems, and the Transmission Provider has 20 additional

Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the Transmission Provider uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

8.1 Are directly interconnected with the Transmission Provider's electric system; or

8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request to interconnect with the Transmission Provider's electric system.

9.0 A distribution system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the Transmission Provider's queuing procedures.

10.0 A deposit of the equivalent of the good faith estimated cost of a distribution system impact study and the one half the good faith estimated cost of a transmission system impact study may be required from the Interconnection Customer.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of ___________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

14.0 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

15.0 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

16.0 Waiver

16.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

16.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of

which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

19.0 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

20.0 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

20.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and

conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider] [Insert name of Interconnection Customer]

______________________________ ____________________________________

Signed: ______________________ Signed: ____________________________

Name (Printed): Name (Printed):

______________________________ ____________________________________

Title: ________________________ Title: _____________________________

Attachment A to System
Impact Study Agreement

Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Attachment 8
Facilities Study Agreement

THIS AGREEMENT is made and entered into this _____day of_______________

20___ by and
between____,

a ______________________________organized and existing under the laws of the State of

____, ("Interconnection Customer,") and

____,
a________________

existing under the laws of the State
of____,

("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on______________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a system impact study and provided the results of said study to the Interconnection Customer; and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a facilities study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the system impact study in accordance with Good Utility Practice to physically and electrically connect the Small Generating Facility with the Transmission Provider's Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause a facilities study consistent with the standard Small Generator Interconnection Procedures to be performed in accordance with the Open Access Transmission Tariff.

3.0 The scope of the facilities study shall be subject to data provided in Attachment A to this Agreement.

4.0 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s). The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Transmission Provider's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities.

5.0 The Transmission Provider may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities.

6.0 A deposit of the good faith estimated facilities study costs may be required from the Interconnection Customer.

7.0 In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days.

8.0 Once the facilities study is completed, a draft facilities study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the facilities study must be completed and the draft facilities study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a facilities study.

9.0 Interconnection Customer may, within 30 Calendar Days after receipt of the draft report, provide written comments to Transmission Provider, which Transmission Provider shall include in the final report. Transmission Provider shall issue the final Interconnection Facilities Study report within 15 Business Days of receiving Interconnection Customer’s comments or promptly upon receiving Interconnection Customer’s statement that it will not provide comments. Transmission Provider may reasonably extend such fifteen-day period upon notice to Interconnection Customer if

Interconnection Customer's comments require Transmission Provider to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Report. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 4.5 of the standard Small Generator Interconnection Procedures.

10.0 Within ten 10 Business Days of providing a draft Interconnection Facilities Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Facilities Study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 <u>Governing Law, Regulatory Authority, and Rules</u>
The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of ___________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

14.0 <u>Amendment</u>
The Parties may amend this Agreement by a written instrument duly executed by both Parties.

15.0 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or

benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

16.0 Waiver

16.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

16.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

19.0 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this

Agreement shall remain in full force and effect.

20.0 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

20.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal

Power Act and

FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider] [Insert name of Interconnection Customer]

______________________________ ____________________________________

Signed________________________ Signed_____________________________

Name (Printed): Name (Printed):

______________________________ ____________________________________

Title__________________________ Title______________________________

Attachment A to
Facilities Study Agreement

Data to Be Provided by the Interconnection Customer
with the Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

On the one-line diagram, indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections: _____________

Will an alternate source of auxiliary power be available during CT/PT maintenance?
Yes ____ No ____

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes ____ No ____ (Please indicate on the one-line diagram).

What type of control system or PLC will be located at the Small Generating Facility?

____

____

What protocol does the control system or PLC use?

____

____

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

Physical dimensions of the proposed interconnection station:

____
____

Bus length from generation to interconnection station:

____
____

Line length from interconnection station to Transmission Provider's Transmission System.

____
____

Tower number observed in the field. (Painted on tower leg)*:

____
____

Number of third party easements required for transmission lines*:

____
____

* To be completed in coordination with Transmission Provider.

Is the Small Generating Facility located in Transmission Provider's service area?
Yes _____ No _____ If No, please provide name of local provider:

____
____

Please provide the following proposed schedule dates:

Begin Construction Date: ______________________

Generator step-up transformers receive back feed power Date: ______________________

Generation Testing Date: ______________________

Commercial Operation Date: ___________________________

ATTACHMENT 9

SMALL GENERATOR INTERCONNECTION AGREEMENT (SGIA)

(For Generating Facilities No Larger Than 20 MWs)

TABLE OF CONTENTS

This Interconnection Agreement ("Agreement") is made and entered into this __________day of _________________, 20__, by ___ Tri-State Generation and Transmission Association, Inc., a cooperative corporation organized and existing under the laws of the state of Colorado

("Transmission Provider"), and ____
("Interconnection Customer") each hereinafter sometimes referred to individually as "Party" or both referred to collectively as the "Parties."

Transmission Provider Information

Transmission Provider: ___________________________________
Attention: ____
Address: ____
City:_____________________________State: _____________ Zip:
Phone: Fax:

Interconnection Customer Information

Interconnection Customer: ________________________________
Attention: ____
Address: ____
City:_____________________________State: _____________ Zip:
Phone: Fax:

Interconnection Customer Application No: ____________

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 This Agreement shall be used for all Interconnection Requests submitted under the Small Generator Interconnection Procedures (SGIP) except for those submitted under the 10 kW Inverter Process contained in SGIP Attachment 5.

1.2 This Agreement governs the terms and conditions under which the Interconnection Customer’s Small Generating Facility will interconnect with, and operate in parallel with, the Transmission Provider's Transmission System.

1.3 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity with the applicable Transmission Provider.

1.4 Nothing in this Agreement is intended to affect any other agreement between the Transmission Provider and the Interconnection Customer.

1.5 <u>Responsibilities of the Parties</u>

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Small Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Transmission Provider shall construct, operate, and maintain its Transmission System and Interconnection Facilities in accordance with this Agreement, and with Good Utility Practice.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Small Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the system or equipment of the Transmission Provider and any Affected Systems.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Attachments to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of change of ownership. The Transmission Provider and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the Transmission Provider's Transmission System, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Agreement.

1.5.6 The Transmission Provider shall coordinate with all Affected Systems to support the interconnection.

1.5.7 The Interconnection Customer shall ensure “frequency ride through” capability and “voltage ride through” capability of its Small Generating Facility. The Interconnection Customer shall enable these capabilities such that its Small Generating Facility shall not disconnect automatically or instantaneously from the system or equipment of the Transmission Provider and any Affected Systems for a defined under-frequency or over-frequency condition, or an under-voltage or over-voltage condition, as tested pursuant to section 2.1 of this Agreement. The

defined conditions shall be in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The Small Generating Facility's protective equipment settings shall comply with the Transmission Provider's automatic load-shed program. The Transmission Provider shall review the protective equipment settings to confirm compliance with the automatic load-shed program. The term "ride through" as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority on a comparable basis. The term "frequency ride through" as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The term "voltage ride through" as used herein shall mean the ability of a Small Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-voltage and over-voltage conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis.

1.6 Parallel Operation Obligations

Once the Small Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Small Generating Facility in the applicable control area, including, but not limited to; 1) the rules and procedures concerning the operation of generation set forth in the Tariff or by the applicable system operator(s) for the Transmission Provider's Transmission System and; 2) the Operating Requirements set forth in Attachment 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the Transmission Provider's reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachments 2 and 3 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

1.8 Reactive Power and Primary Frequency Response

1.8.1 Power Factor Design Criteria

1.8.1.1 Synchronous Generation. The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all similarly situated synchronous generators in the control area on a comparable basis.

1.8.1.2 Non-Synchronous Generation. The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all similarly situated non-synchronous generators in the control area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of the Final Rule establishing this requirement (Order No. 827).

1.8.2 The Transmission Provider is required to pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs from the Small Generating Facility when the Transmission Provider requests the Interconnection Customer to operate its Small Generating Facility outside the range specified in article 1.8.1. In addition, if the Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.

1.8.3 Payments shall be in accordance with the Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to a regional transmission organization or independent system operator FERC-approved rate schedule. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb reactive power under this Agreement, the Parties agree to expeditiously file such rate schedule and agree to support any request for waiver of the Commission's prior notice requirement in order to compensate the Interconnection Customer from the time service commenced.

1.8.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Small Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term “functioning governor or equivalent controls” as used herein shall mean the

required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Small Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Small Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based on an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Small Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Small Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Small Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Small Generating Facility with the Transmission System, Interconnection Customer shall operate the Small Generating Facility consistent with the provisions specified in Sections 1.8.4.1 and 1.8.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Small Generating Facilities.

1.8.4.1 <u>Governor or Equivalent Controls.</u> Whenever the Small Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Small Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Small Generating Facility with its governor or equivalent controls not in service,

Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Small Generating Facility's governor or equivalent controls to a minimum whenever the Small Generating Facility is operated in parallel with the Transmission System.

1.8.4.2 Timely and Sustained Response. Interconnection Customer shall ensure that the Small Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Small Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Small Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

1.8.4.3 Exemptions. Small Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 1.8.4, 1.8.4.1, and 1.8.4.2 of this Agreement. Small Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 1.8.4, but shall be otherwise exempt from the operating requirements in Sections 1.8.4, 1.8.4.1, 1.8.4.2, and 1.8.4.4 of this Agreement.

1.8.4.4 Electric Storage Resources. Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Attachment 5 of its SGIA that specifies a minimum state of charge and a maximum state

of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 1.8.4, 1.8.4.1, 1.8.4.2 and 1.8.4.3 of this Agreement. Attachment 5 shall specify whether the operating range is static or dynamic, and shall consider: (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Attachment 5 must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 1.8.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

1.9Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

2.1.1 The Interconnection Customer shall test and inspect its Small Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the Transmission Provider of such activities no fewer than five Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day. The

Transmission Provider may, at its own expense, send qualified personnel to the Small Generating Facility site to inspect the interconnection and observe the testing. The Interconnection Customer shall provide the Transmission Provider a written test report when such testing and inspection is completed.

2.1.2 The Transmission Provider shall provide the Interconnection Customer written acknowledgment that it has received the Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Transmission Provider of the safety, durability, suitability, or reliability of the Small Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Small Generating Facility.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The Transmission Provider shall use Reasonable Efforts to list applicable parallel operation requirements in Attachment 5 of this Agreement. Additionally, the Transmission Provider shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The Transmission Provider shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

2.2.2 The Interconnection Customer shall not operate its Small Generating Facility in parallel with the Transmission Provider's Transmission System without prior written authorization of the Transmission Provider. The Transmission Provider will provide such authorization once the Transmission Provider receives notification that the Interconnection Customer has complied with all applicable parallel operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

2.3 Right of Access

2.3.1 Upon reasonable notice, the Transmission Provider may send a qualified person to the premises of the Interconnection Customer at or immediately before the time the Small Generating Facility first produces energy to inspect the interconnection, and observe the commissioning of the Small Generating Facility (including any required testing), startup, and operation for a period of up to three Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Transmission Provider at least five Business Days prior to conducting any on-site verification testing of the Small Generating Facility.

2.3.2 Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Transmission Provider shall have access to the

Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

2.3.3 Each Party shall be responsible for its own costs associated with following this article.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by the FERC. The Transmission Provider shall promptly file this Agreement with the FERC upon execution, if required.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date and shall remain in effect for a period of ten years from the Effective Date or such other longer period as the Interconnection Customer may request and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with article 3.3 of this Agreement.

3.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this Agreement (if required), which notice has been accepted for filing by FERC.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Transmission Provider 20 Business Days written notice.

3.3.2 Either Party may terminate this Agreement after Default pursuant to article 7.6.

3.3.3 Upon termination of this Agreement, the Small Generating Facility will be disconnected from the Transmission Provider's Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this SGIA or such non-terminating Party otherwise is responsible for these costs under this SGIA.

3.3.4 The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

3.3.5 The provisions of this article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

Temporary disconnection shall continue only for so long as reasonably necessary under Good Utility Practice.

3.4.1 Emergency Conditions -- "Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, the Transmission Provider's Interconnection Facilities or the Transmission Systems of others to which the Transmission System is directly connected; or (3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Small Generating Facility or the Interconnection Customer's Interconnection Facilities. Under Emergency Conditions, the Transmission Provider may immediately suspend interconnection service and temporarily disconnect the Small Generating Facility. The Transmission Provider shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Small Generating Facility. The Interconnection Customer shall notify the Transmission Provider promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Transmission Provider's Transmission System or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

The Transmission Provider may interrupt interconnection service or curtail the output of the Small Generating Facility and temporarily disconnect the Small Generating Facility from the Transmission Provider's Transmission System when necessary for routine maintenance, construction, and repairs on the Transmission Provider's Transmission System. The Transmission Provider shall provide the Interconnection Customer with five Business Days notice prior to such interruption. The Transmission Provider shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

3.4.3 Forced Outages

During any forced outage, the Transmission Provider may suspend interconnection service to effect immediate repairs on the Transmission Provider's Transmission System. The Transmission Provider shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Transmission Provider shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 Adverse Operating Effects

The Transmission Provider shall notify the Interconnection Customer as soon as

practicable if, based on Good Utility Practice, operation of the Small Generating Facility may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Small Generating Facility could cause damage to the Transmission Provider's Transmission System or Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Transmission Provider may disconnect the Small Generating Facility. The Transmission Provider shall provide the Interconnection Customer with five Business Day notice of such disconnection, unless the provisions of article 3.4.1 apply.

3.4.5 Modification of the Small Generating Facility

The Interconnection Customer must receive written authorization from the Transmission Provider before making any change to the Small Generating Facility that may have a material impact on the safety or reliability of the Transmission System. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the Transmission Provider's prior written authorization, the latter shall have the right to temporarily disconnect the Small Generating Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Small Generating Facility, Interconnection Facilities, and the Transmission Provider's Transmission System to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Attachment 2 of this Agreement. The Transmission Provider shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, and the Transmission Provider.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Transmission Provider's Interconnection Facilities.

4.2 Distribution Upgrades

The Transmission Provider shall design, procure, construct, install, and own the Distribution Upgrades described in Attachment 6 of this Agreement. If the Transmission Provider and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer.

Article 5. Cost Responsibility for Network Upgrades

5.1 Applicability

No portion of this article 5 shall apply unless the interconnection of the Small Generating Facility requires Network Upgrades.

5.2 Network Upgrades

The Transmission Provider or the Transmission Owner shall design, procure, construct, install, and own the Network Upgrades described in Attachment 6 of this Agreement. If the Transmission Provider and the Interconnection Customer agree, the Interconnection Customer may construct Network Upgrades that are located on land owned by the Interconnection Customer. Unless the Transmission Provider elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, shall be borne initially by the Interconnection Customer.

5.2.1 Repayment of Amounts Advanced for Network Upgrades

The Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to the Transmission Provider and Affected System operator, if any, for Network Upgrades, including any tax gross-up or other tax-related payments associated with the Network Upgrades, and not otherwise refunded to the Interconnection Customer, to be paid to the Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under the Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Small Generating Facility. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC’s regulations at 18 C.F.R. § 35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. The Interconnection Customer may assign such repayment rights to any person.

5.2.1.1 Notwithstanding the foregoing, the Interconnection Customer, the Transmission Provider, and any applicable Affected System operators may adopt any alternative payment schedule that is mutually agreeable so long as the Transmission Provider and said Affected System operators take one of the following actions no later than five years from the Commercial Operation Date: (1) return to the Interconnection Customer any amounts advanced for Network Upgrades not previously repaid, or

(2) declare in writing that the Transmission Provider or any applicable Affected System operators will continue to provide payments to the Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond twenty (20) years from the commercial operation date.

5.2.1.2 If the Small Generating Facility fails to achieve commercial operation, but it or another generating facility is later constructed and requires use of the Network Upgrades, the Transmission Provider and Affected System operator shall at that time reimburse the Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the generating facility, if different, is responsible for identifying the entity to which reimbursement must be made.

5.3 Special Provisions for Affected Systems

Unless the Transmission Provider provides, under this Agreement, for the repayment of amounts advanced to any applicable Affected System operators for Network Upgrades, the Interconnection Customer and Affected System operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by the Interconnection Customer to Affected System operator as well as the repayment by Affected System operator.

5.4 Rights Under Other Agreements

Notwithstanding any other provision of this Agreement, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that the Interconnection Customer shall be entitled to, now or in the future, under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Small Generating Facility.

Article 6. Billing, Payment, Milestones, and Financial Security

6.1 Billing and Payment Procedures and Final Accounting

6.1.1 The Transmission Provider shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of Interconnection Facilities and Upgrades contemplated by this Agreement on a monthly basis, or as otherwise agreed by the Parties. The Interconnection Customer shall pay each bill within 30 calendar days of receipt, or as otherwise agreed to by the Parties.

6.1.2 Within three months of completing the construction and installation of the Transmission Provider's Interconnection Facilities and/or Upgrades described in the Attachments to this Agreement, the Transmission Provider shall provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the Transmission Provider for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Transmission Provider shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Transmission Provider within 30 calendar days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Transmission Provider shall refund to the Interconnection Customer an amount equal to the difference within 30 calendar days of the final accounting report.

6.2 Milestones

The Parties shall agree on milestones for which each Party is responsible and list them in Attachment 4 of this Agreement. A Party's obligations under this provision may be extended by agreement. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, it shall immediately notify the other Party of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) requesting appropriate amendments to Attachment 4. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless it will suffer significant uncompensated economic or operational harm from the delay, (2) attainment of the same milestone has previously been delayed, or (3) it has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment.

6.3 Financial Security Arrangements

At least 20 Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Transmission Provider's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the Transmission Provider, at the Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to the Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction where the Point of Interconnection is located. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Transmission Provider's Interconnection Facilities and Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to the Transmission Provider under this Agreement during its term. In addition:

6.3.1 The guarantee must be made by an entity that meets the creditworthiness requirements of the Transmission Provider, and contain terms and

conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.6.3.2 The letter of credit or surety bond must be issued by a financial institution or insurer reasonably acceptable to the Transmission Provider and must specify a reasonable expiration date.

Article 7. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

7.1 Assignment

This Agreement may be assigned by either Party upon 15 Business Days prior written notice and opportunity to object by the other Party; provided that:

7.1.1 Either Party may assign this Agreement without the consent of the other Party to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement, provided that the Interconnection Customer promptly notifies the Transmission Provider of any such assignment;

7.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Transmission Provider, for collateral security purposes to aid in providing financing for the Small Generating Facility, provided that the Interconnection Customer will promptly notify the Transmission Provider of any such assignment.7.1.3 Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Interconnection Customer. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

7.2 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages, except as authorized by this Agreement.

7.3 Indemnity

7.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in article 7.2.

7.3.2 The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.3.3 If an indemnified person is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

7.3.4 If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

7.3.5 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

7.4 Consequential Damages

Other than as expressly provided for in this Agreement, neither Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

7.5 Force Majeure

7.5.1 As used in this article, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party’s control. A Force Majeure Event

does not include an act of negligence or intentional wrongdoing."

7.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party, either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

7.6 Default

7.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of the other Party. Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in article 7.6.2, the defaulting Party shall have 60 calendar days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within 60 calendar days, the defaulting Party shall commence such cure within 20 calendar days after notice and continuously and diligently complete such cure within six months from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

7.6.2 If a Default is not cured as provided in this article, or if a Default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Agreement.

Article 8. Insurance

8.1 The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to this Agreement. The amount of such insurance shall be sufficient

to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. The Interconnection Customer shall obtain additional insurance only if necessary as a function of owning and operating a generating facility. Such insurance shall be obtained from an insurance provider authorized to do business in the State where the interconnection is located. Certification that such insurance is in effect shall be provided upon request of the Transmission Provider, except that the Interconnection Customer shall show proof of insurance to the Transmission Provider no later than ten Business Days prior to the anticipated commercial operation date. An Interconnection Customer of sufficient credit-worthiness may propose to self-insure for such liabilities, and such a proposal shall not be unreasonably rejected.

8.2 The Transmission Provider agrees to maintain general liability insurance or self-insurance consistent with the Transmission Provider’s commercial practice. Such insurance or self-insurance shall not exclude coverage for the Transmission Provider's liabilities undertaken pursuant to this Agreement.

8.3 The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

Article 9. Confidentiality

9.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

9.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

9.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

9.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information

without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

9.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this Agreement prior to the release of the Confidential Information to FERC. The Party shall notify the other Party to this Agreement when it is notified by FERC that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

Article 10. Disputes

10.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

10.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

10.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

10.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at http://www.ferc.gov/legal/adr.asp.

10.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.

10.6 If neither Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of this Agreement.

Article 11. Taxes

11.1 The Parties agree to follow all applicable tax laws and regulations, consistent with FERC

policy and Internal Revenue Service requirements.

11.2 Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this Agreement is intended to adversely affect the Transmission Provider's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

Article 12. Miscellaneous

12.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of ____________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties, or under article 12.12 of this Agreement.

12.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

12.4 Waiver

12.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

12.4.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

12.5 Entire Agreement

This Agreement, including all Attachments, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements,

representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

12.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

12.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

12.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

12.9 Security Arrangements

Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. FERC expects all Transmission Providers, market participants, and Interconnection Customers interconnected to electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

12.10 Environmental Releases

Each Party shall notify the other Party, first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Small Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

12.11 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

12.11.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

12.11.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

12.12 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

Article 13. Notices

13.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Interconnection Customer:

Interconnection Customer: ______________________________________
Attention: __________________________________
Address: ____
City:_________________________________State: ______________ Zip:
Phone: Fax:

If to the Transmission Provider:

Transmission Provider:____
Attention: __________________________________
Address: ____
City:_________________________________State: ______________ Zip:
Phone: Fax:

13.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

Interconnection Customer: ____
Attention: __________________________________
Address: ____
City:_________________________________State: ______________ Zip:

Transmission Provider:____
Attention: __________________________________
Address: ____
City:_________________________________State: ______________ Zip:

13.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by either Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

If to the Interconnection Customer:

Interconnection Customer: ______________________________________

Attention: ______________________________
Address: ____
City:_____________________________State: ____________ Zip:
Phone: Fax:

If to the Transmission Provider:

Transmission Provider:____________________________________
Attention: ______________________________
Address: ____
City:_____________________________State: ____________ Zip:
Phone: Fax:

13.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's Operating Representative:

Interconnection Customer: ________________________________
Attention: ______________________________
Address: ____
City:_____________________________State: ____________ Zip:
Phone: Fax:

Transmission Provider's Operating Representative:

Transmission Provider:____________________________________
Attention: ______________________________
Address: ____
City:_____________________________State: ____________ Zip:
Phone: Fax:

13.5 Changes to the Notice Information

Either Party may change this information by giving five Business Days written notice prior to the effective date of the change.

Article 14. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Transmission Provider

Name:

Title:

Date:

For the Interconnection Customer

Name:

Title:

Date:

Attachment 1

Glossary of Terms

Affected System – An electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local

laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Business Day – Monday through Friday, excluding Federal Holidays.

Default – The failure of a breaching Party to cure its breach under the Small Generator Interconnection Agreement.

Distribution System – The Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Interconnection Provider, or any Affiliate thereof.

Interconnection Customer – Any entity, including the Transmission Provider, the Transmission Owner or any of the affiliates or subsidiaries of either, that proposes to interconnect its Small

Generating Facility with the Transmission Provider's Transmission System.

Interconnection Facilities – The Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of

Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Request – The Interconnection Customer's request, in accordance with the Tariff, to interconnect a new Small Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the Transmission Provider’s Transmission System.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Network Upgrades – Additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Transmission Provider’s Transmission System to accommodate the interconnection of the Small Generating Facility with the Transmission Provider’s Transmission System. Network Upgrades do not include Distribution Upgrades.

Operating Requirements – Any operating and technical requirements that may be applicable due to Regional Transmission Organization, Independent System Operator, control area, or the Transmission Provider's requirements, including those set forth in the Small Generator Interconnection Agreement.

Party or Parties – The Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Transmission Provider's Transmission System.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under the Small Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Generating Facility – The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Tariff – The Transmission Provider or Affected System's Tariff through which open access transmission service and Interconnection Service are offered, as filed with the FERC, and as

amended or supplemented from time to time, or any successor tariff.

Transmission Owner – The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Small Generator Interconnection Agreement to the extent necessary.

Transmission Provider – Tri-State Generation and Transmission Association, Inc., the public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission System – The facilities owned, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service under the Tariff.

Upgrades – The required additions and modifications to the Transmission Provider's Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Attachment 2

Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment

Equipment, including the Small Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer, the Transmission Provider, or the Transmission Owner. The Transmission Provider will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

Attachment 3

One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades

Attachment 4

Milestones

In-Service Date:

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	Responsible Party
(1)		
(2)		
(3)		
(4)		
(5)		
(6)		
(7)		
(8)		
(9)		

(0)

Agreed to by:

For the Transmission Provider ___________________________ Date _________

For the Transmission Owner (If Applicable) __________________________Date

For the Interconnection Customer _________________________ Date________

Attachment 5

Additional Operating Requirements for the Transmission Provider's Transmission System and Affected Systems Needed to Support the Interconnection Customer's Needs

The Transmission Provider shall also provide requirements that must be met by the Interconnection Customer prior to initiating parallel operation with the Transmission Provider's Transmission System.

Attachment 6

Transmission Provider's Description of its Upgrades and Best Estimate of Upgrade Costs

The Transmission Provider shall describe Upgrades and provide an itemized best estimate of the cost, including overheads, of the Upgrades and annual operation and maintenance expenses associated with such Upgrades. The Transmission Provider shall functionalize Upgrade costs and annual expenses as either transmission or distribution related.

g the study, and Tri-State shall either refund any over-collection or bill any under-collection after completion of the study.

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nsmission Customer:

By:
Name Title Date

Ancillary Services Charges:

Document Content(s)